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16. ABSTRACT The report documents results of an evaluation to verify the accuracy of simplified procedures for estimating sulfur dioxide (SO2) and nitrogen oxides (NOx) retrofit control costs and performance for 200 SO2-emitting coal-fired power plants in the 31-state eastern region. Initially, detailed retrofit studies were conducted for 12 coal-fired plants in Ohio, Kentucky, and the Tennessee Valley Authority system. Because detailed studies are expensive and time-consuming, results from the 12-plant study were used to develop simplified procedures which require less time, data, and preparation effort. The evaluation compared the costs for a number of plants estimated using the simplified procedures to costs estimated using detailed procedures, actual retrofit costs, and more detailed cost estimates provided by utility companies. Based on the evaluation, recommendations for changes to the simplified procedures were developed. Control technologies addressed in the report are conventional lime/limestone flue gas desulfurization, lime spray drying, furnace sorbent injection, duct spray drying, coal switching, physical coal cleaning, and selective catalytic reduction. In general, it was found that the simplified procedures can be used to generate improved cost performance estimates based on generally available information: USGS photographs and EIA Form-767 data.

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ABSTRACT

Detailed retrofit studies were conducted for 12 coal-fired plants in Ohio, Kentucky, and the Tennessee Valley Authority system. Because detailed studies are expensive and time-consuming, the results from the 12-plant study were used to develop simplified procedures for estimating sulfur dioxide (SO_2) and nitrogen oxides (NO_x) retrofit control costs and performance for 200 SO_2-emitting coal-fired power plants in the 31-state eastern region. The simplified procedures require less time, data, and preparation effort. This report documents the results of an evaluation to verify the accuracy of the simplified procedures. The evaluation compared the costs for a number of plants estimated using the simplified procedures to costs estimated using detailed procedures, actual retrofit costs, and more detailed cost estimates provided by utility companies. Based on the evaluation, recommendations for changes to the simplified procedures were developed. Control technologies addressed in this report are conventional lime/limestone flue gas desulfurization, lime spray drying, furnace sorbent injection, duct spray drying, coal switching, physical coal cleaning, and selective catalytic reduction. In general, it was found that the simplified procedures can be used to generate improved cost performance estimates based on generally available information: U. S. Geological Survey photographs and Energy Information Agency Form 767 data.

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ABBREVIATIONS AND SYMBOLS

ABBREVIATIONS

A&E -- architectural and engineering

acfm -- actual cubic feet per minute

AEERL -- Air and Energy Engineering Research Laboratory

AEP -- American Electric Power

AF -- allowance factor

AFDC -- allowance for funds during construction

CG&E -- Cincinnati Gas and Electric

CS -- coal switching

CS/B -- coal switching and blending

DOE -- Department of Energy

DSD -- duct spray drying

EIA-767 -- Energy Information Agency Form 767

EPA -- Environmental Protection Agency

EPRI -- Electric Power Research Institute

ESP -- electrostatic precipitator

FF -- fabric filter

FGD -- flue gas desulfurization

FSI -- furnace sorbent injection

IAPCS -- Integrated Air Pollution Control System

IRS -- Internal Revenue Service

KU -- Kentucky Utilities

kW -- kilowatt

kW-h -- killowatt-hour

L/LS -- lime/limestone

ABBREVIATIONS AND SYMBOLS (Continued)

LNC -- low-NO_x combustion

LSD -- lime spray drying

MW -- megawatt

NAPAP -- National Acidic Precipitation Assessment Program

NGR -- natural gas reburning

NRDC -- Natural Rescources Defense Council

NSPS -- new source performance standard

OEUI -- Ohio Electric Utility Institute

O&M -- operating and maintenance

PCC -- physical coal cleaning

psia -- pounds per square inch absolute

S&L -- Sargent and Lundy

SCA -- specific collection area (ft^2/1000 acfm)

SCR -- selective catalytic reduction

SI -- sorbent injection

sq ft -- square feet

TAG -- Technical Assessment Guideline

TVA -- Tennessee Valley Authority

UARG -- Utility Air Regulatory Group

USGS -- U.S. Geological Survey

$/kW -- dollars per kilowatt

SYMBOLS

NO_x -- nitrogen oxides

SO_2 -- sulfur dioxide

SO_3 -- sulfur trioxide

SECTION 1

INTRODUCTION

The objective of the NAPAP retrofit cost project is to develop improved (site-specific) cost estimates for retrofitting sulfur dioxide (SO_2) and nitrogen oxide (NO_x) controls on 200 of the largest emitting coal-fired utility power plants. This project was conducted in several phases and depicted on Figure 1-1. In the first phase, procedures were developed based on plant-specific information obtained from site visits (detailed procedures). Twelve plants in Kentucky, Ohio, and the Tennessee Valley Authority (TVA) were evaluated under this program phase (1), and the procedures and results were reviewed by a Technical Advisory Committee and the participating utility companies.

Because detailed studies are expensive and time consuming, the results of the 12-plant study were used to develop simplified procedures for estimating SO_2/NO_x control technology retrofit cost/performance for 200 SO_2-emitting coal-fired power plants in the 31-state eastern region. In simplifying the detailed procedures, the major retrofit factor "drivers" were identified and only the retrofit difficulties associated with these drivers (e.g., site access and congestion) were estimated. To estimate retrofit factors using the simplified procedures, a plot plan and/or aerial photograph were used instead of information gathered through a site visit. However, assumptions were made to streamline these procedures. For example, average underground obstructions as well as some scope adjustments were always used (e.g., chimney liner, demolition and relocation, draft controls, and new rails) unless one or more of these items were unnecessary or incorrect. After developing cost/performance estimates for 50 plants using the simplified procedures, these procedures were evaluated to verify their accuracy. The results of the simplified procedures were compared to the following:

- results obtained by using the detailed procedures,
- actual retrofit cost, and
- more detailed estimates provided by participating utility companies.

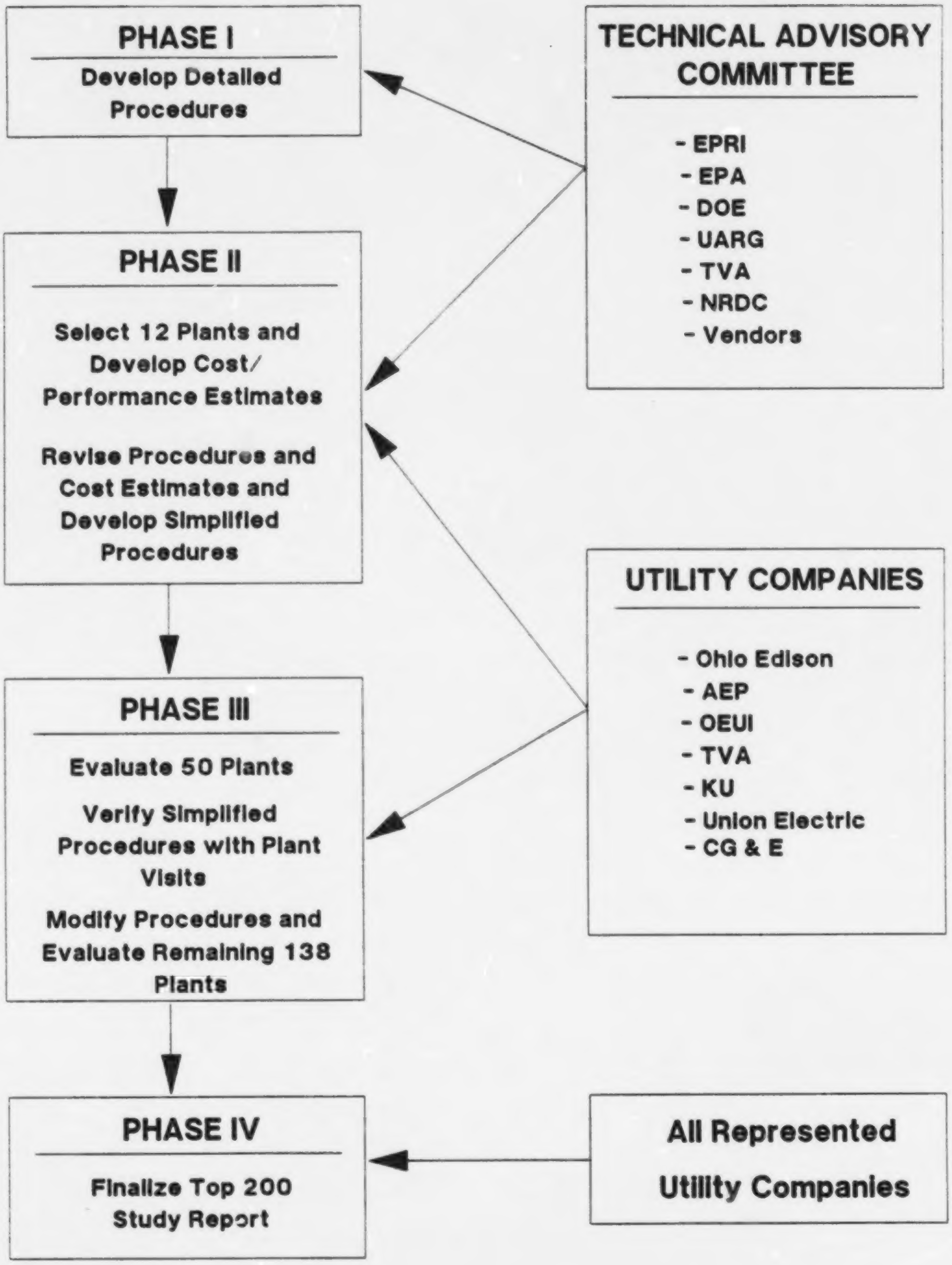
PHASE I
Develop Detailed Procedures
PHASE II
Select 12 Plants and Develop Cost/ Performance Estimates
Revise Procedures and Cost Estimates and Develop Simplified Procedures
PHASE III
Evaluate 50 Plants
Verify Simplified Procedures with Plant Visits
Modify Procedures and Evaluate Remaining 138 Plants
PHASE IV
Finalize Top 200 Study Report
TECHNICAL ADVISORY COMMITTEE
- EPRI
- EPA
- DOE
- UARG
- TVA
- NRDC
- Vendors
UTILITY COMPANIES
- Ohio Edison
- AEP
- OEUI
- TVA
- KU
- Union Electric
- CG & E
All Represented Utility Companies

Figure 1-1. Top 200 Plant Study technical approach.

To accomplish this objective, 6 plants were selected from the 50 plants to evaluate the simplified procedures. Additionally, for 17 boilers, detailed cost estimates or reported actual costs for retrofit FGD systems were available to compare to the detailed and simplified procedure results generated under this program.

This report presents the SO_2/NO_x control technology cost and performance estimates developed. Results for the four plants in Missouri are presented in Sections 3-6, and the results for the two plants in Ohio are presented in Section 7. The following procedures were used to develop the cost performance estimates: select plants with boilers representative of the population, conduct plant visits and collect site-specific data, develop boiler/control-specific retrofit difficulty factors, develop boiler/plant-specific cost and performance estimates for the SO_2 and NO_x controls selected using the detailed procedures, and compare these results with results developed using simplified procedures. Utility interest in participation in the study was a major consideration in plant selection. Table 1-1 presents the boiler characteristics for the six plants visited to verify and quantify the accuracy of the simplified procedures.

1.1 SIMPLIFIED PROCEDURES VERIFICATION METHODOLOGY

Table 1-2 presents the SO_2/NO_x control technologies that are being evaluated under the NAPAP retrofit control cost study. As this table shows, detailed and simplified procedures were developed for the lime/limestone (L/LS) and lime spray drying (LSD) flue gas delulfurization (FGD) technologies. However, for the other technologies only simplified procedures were developed. The focus of the simplified procedure verification evaluation was twofold. First, the accuracy of the publicly available data and the assumptions used to develop the inputs to the simplified procedures were reviewed. These inputs were then compared to the inputs developed using the more detailed data obtained from the site visits.

Second, for the FGD technologies, retrofit factors and indirect costs were developed using the detailed procedures. These retrofit factors and indirects were compared to the simplified procedure results developed before the site visits as well as the simplified procedure results developed with the

TABLE 1-1. BOILER CHARACTERISTICS OF THE PLANTS EVALUATED

Plant Name	Boiler Number	Gross Operating Capacity (MW)[a]	Installation Date	Capacity Factor (%)	Firing Type	Coal Sulfur (%)
Rush Island	1	621	1976	42	Tangential	1.1
	2	621	1977	58	Tangential	1.1
Sioux	1	550	1967	43	Cyclone	2.5
	2	550	1967	32	Cyclone	2.5
Meramec	1	137	1953	10	Tangential	1.1
	2	137	1954	12	Tangential	1.1
	3	289	1959	11	Wall	1.1
	4	359	1961	11	Wall	1.1
Labadie	1	620	1970	59	Tangential	2.6
	2	620	1970	52	Tangential	2.6
	3	620	1973	57	Tangential	2.6
	4	620	1973	58	Tangential	2.6
Beckjord	1	100	1952	6	Tangential	1.0
	2	100	1952	8	Tangential	1.0
	3	135	1954	10	Wall	1.0
	4	162	1958	22	Tangential	1.0
	5	255	1962	29	Tangential	2.5
	6	449	1969	57	Tangential	2.5
Miami Fort	5	85	1949	40	Wall	1.0
	6	175	1960	71	Tangential	1.0
	7	524	1975	67	Wall	3.0

[a] Maximum unit design capability.

site visit information. This was done so that differences in the detailed procedures and the simplified procedures could be classified as being due to errors in the quality of the publicly available information or due to the different level of detail between the two procedures.

TABLE 1-2. EMISSION CONTROL TECHNOLOGIES EVALUATED

	Species Controlled		Development Status			Type of Procedures	
	SO_2	NO_x	Commercial	Limited Commercial Experience	Near Commercial Demonstration	Detailed	Simplified
Lime/Limestone (L/LS) flue gas desulfurization (FGD)	X		X			X	X
Additive enhanced L/LS-FGD	X		X			X	X
Lime spray drying (LSD) FGD[a]	X		X		X	X	X
Physical coal cleaning (PCC)	X		X				X
Coal switching and blending (CS/B)	X		X				X
Low-NO_x combustion (LNC)		X		X			X
Furnace sorbent injection (FSI) with humidification	X				X		X
Duct spray drying (DSD)	X				X		X
Natural gas reburning (NGR)[b]	X	X			X		X
Selective catalytic reduction (SCR)		X		X			X

[a] Commercial on low sulfur coals, demonstrated at pilot scale on high sulfur coals.

[b] For wet bottom boilers and other boilers where LNC is not applicable.

Additionally, when actual cost data or more detailed cost estimates were available, these costs were compared to the costs estimated using the simplified and detailed procedures. Actual retrofit costs were obtained from the Department of Energy (DOE) Energy Information Agency (EIA) 767 forms for seven units at six plants. Detailed engineering cost estimates were obtained for 10 units at 6 plants.

Cost estimates developed under this study were generated using the Integrated Air Pollution Control System (IAPCS) cost model. These cost estimates were made to reflect site-specific retrofit impacts by inputting capital cost multipliers, scope adder costs, and capital cost indirect factors that were developed using the simplified and detailed procedures.

1.2 FGD PROCEDURES

1.2.1 Comparison of Simplified and Detailed Procedure Results

For L/LS and LSD-FGD, retrofit factors and cost estimates were developed using both the simplified and detailed procedures based on the detailed information collected during the site visits. The retrofit factors and cost estimates were then compared to those previously developed using the simplified procedures and based on EIA-767 data and plant plot plans or aerial photographs.

The percent differences between the simplified and detailed procedures based on the data obtained from the site visits are small. The percent difference for L/LS-FGD varied between -6 and 5 percent with an average of 2.7 percent. The percent difference for LSD-FGD varied between <1 and 5 percent with an average of 1.9 percent. These differences are due to simplifying assumptions made when developing the simplified procedures.

The differences between the detailed procedures and the simplified procedure results based on publicly available data were also determined. The percent difference for L/LS-FGD varied from -9 to 16 percent with an average of 8.8 percent. The percent difference for LSD-FGD varied from -24 to 17 percent with an average of 9.8 percent.

The difference between the simplified and detailed procedure results are due to procedural differences and errors in assumptions due to having less detailed and incorrect data. The procedural differences result from simplifying the detailed procedures by using average factors for flue gas duct distance, underground obstruction difficulties, and scope adder costs. The incorrect data resulted in changing the need for wet to dry ash handling at the four Missouri plants. Additionally, the absorber locations for one of the Missouri plants, Meramec units 1-4, were changed. Duct work distance and absorber/flue gas handling area access/congestion changes were also made at Labadie and Rush Island when more detailed information was available. A comparison of the simplified procedure results, developed before and refined after the site visits for the two Ohio plants, revealed no significant differences.

Based on these results, it was concluded that the use of EIA-767 form data and U.S. Geological Survey (USGS) photographs can be used to accurately determine the retrofit difficulty for FGD. However, experience is needed to accurately evaluate these sources of information. Additionally, communications with the plant generally can be very helpful in confirming the best location of the FGD process areas and retrofit difficulty issues.

1.2.2 Comparison to Other Cost Estimates

Capital cost estimates using the simplified procedures were developed and compared to estimates developed by architectural and engineering (A&E) firms for six plants. These cost estimates were obtained through the data collection effort for the program. Table 1-3 summarizes the results of this comparison. As can be seen, the simplified procedure results compare well with the A&E estimates. The percent difference varied from -12 to +20, well within ±30 percent accuracy of the Electric Power Research Institute (EPRI) FGD cost estimating guidelines. Discussion of the Beckjord and Miami Fort plants is presented in Section 7.

TABLE 1-3. COMPARISON OF CAPITAL COST ESTIMATES[a]

Plant Name and Unit	A&E Estimate ($/kW)	Simplified Procedure Estimate ($/kW)	Absolute[b] Difference (%)
Asbury 1	274	264	4
Sibley 3	199	222	12
Thomas Hill 1	363	355	2
Thomas Hill 2	282	297	5
New Madrid 1	259	221	15
New Madrid 2	215	229	7
Beckjord 5 + 6	203	202	<1
Miami Fort 6	276	283	3
Miami Fort 7	210	169	20

[a] In 1987 dollars.
[b] (A&E estimate - simplified procedure estimate)/A&E estimate * 100.

1.2.3 Comparison of IAPCS Cost Estimates to Actual Installed Costs

A review of the Flue Gas Desulfurization Information System identified 11 retrofit FGD systems that came on line after 1980. For seven of these units, actual costs reported in EIA-767 forms and aerial photographs were available and were used to compare the simplified procedure cost estimates to actual reported costs. For these seven units, FGD system cost estimates have been developed using the IAPCS cost model with retrofit factors developed from the simplified or detailed procedures for the following units: Paradise 1 and 2, Widows Creek 7, Mill Creek 1 and 2, and Four Corners 4 and 5. Table 1-4 summarizes the results of this effort with the actual costs being escalated to the same year dollars as the cost estimates (January 1988).

The cost estimates developed for Four Corners, Paradise, and Mill Creek unit 1 compare well with the reported actual costs. However, the cost estimates for the Mill Creek unit 2 and Widows Creek unit 7 differ significantly. At least two reasons are possible to account for the differences.

1) Mill Creek units 1 and 2 share a common feed and waste handling facility, as do Widows Creek units 7 and 8.

TABLE 1-4. COMPARISON OF RETROFIT FACTORS AND ESTIMATED AND REPORTED COSTS

Plant and Unit	Retrofit Factor	IAPCS Estimated[c] Cost ($/kW)	Reported Actual Cost ($kW)	Absolute[d] Difference (%)
Paradise 1 or 2	1.35	182	184[b]	1
Four Corners 4[a]	1.66	316	303	4
Four Corners 5[a]	1.66	316	303	4
Mill Creek 1	1.26	180	173	4
Mill Creek 2	1.26	180	75	140
Widows Creek 7	1.24	170	140	21

[a] Cost of fabric filters are also included in the FGD cost.
[b] Reference 1.
[c] Includes allowance for funds during construction.
[d] (actual cost - estimated cost)/actual cost * 100.

2) The Mill Creek and Widows Creek units were not current state-of-the-technology designs and have undergone significant design changes since start-up.

All of these factors would reduce the actual cost compared to the estimates developed based on current new source performance standard (NSPS) design. However, despite these differences, the reported costs for Mill Creek 2 and Widows Creek 7 appear to be very low. Note that the most recent FGD system actual costs compare favorably to the IAPCS estimates and that the cost of the more recent units ranges from $180 per kilowatt ($/kW) to $300/kW. Additional comparisons should be made for the other four units at the Cromby, Eddystone, and Mitchell plants if sufficient data are obtained to conduct the evaluation.

1.3 LSD-FGD WITH REUSE OF ELECTROSTATIC PRECIPITATORS (ESP)

As part of the simplified procedure methodology for LSD-FGD, it is assumed that the existing ESP will be used for particulate control if the specific collection area (SCA) is greater than 225 square feet (sq ft) of plate area per 1000 actual cubic feet per minute (acfm, 1000 acfm = 28 actual m^3/min) of flue gas. This was the case for all of the Missouri plants and for several of the Ohio units. However, for many of these units, reusing the ESP would result in very difficult and lengthy flue gas duct runs from the outlet of the air heater to the spray dryer absorbers and back again to the ESP inlet. For units that have space immediately adjacent to the air heater and ESP, this option is more practical. Table 1-5 presents the ESP SCA and comments on applicability of this technology for the six plants visited.

TABLE 1-5. SUMMARY OF LSD-FGD ESP REUSE APPLICABILITY

Plant Name	Unit	ESP SCA[a]	Comments	Applicability
Sioux	1 and 2	268	Marginal SCA; space available on one side; reasonable accessibility to existing flue gas ducting.	Marginal due to SCA
Labadie	1 and 4	319	Good ESP performance; space available on one side; access to existing flue gas ducting is difficult.	Moderate
Labadie	2 and 3	319	Good ESP performance; space not available at sides or behind chimney; access to existing flue gas ducting is very difficult.	Marginal due to SCA
Rush Island	1 and 2	279	Good ESP performance but marginal SCA; reasonable access to existing flue gas ducting; space available on one side and behind chimney.	Marginal due to SCA
Meramec	1-3	492-522	Good ESP performance and SCA; long duct runs and difficult access to existing flue gas ducting because space is only available on far side of unit 4 for absorbers.	Marginal (good, if absorbers are located where original ESPs are)

(Continued)

TABLE 1-5. (Continued)

Plant Name	Unit	ESP SCA	Comments	Applicability
Meramec	4	545	Good ESP performance and SCA; moderate duct runs and accessibility to existing flue gas ducting; space available for absorbers at one side of unit.	Good
Beckjord	1-4	205-244	Marginal ESPs; very poor access for ducting.	Poor
	5	247	Same as above.	Poor
	6	646	Good candidate; easy access.	Good
Miami Fort	5	354	Poor access for duct runs.	Marginal
	6	205	Very small ESP SCA.	Poor
	7	275	Marginal ESP SCA; space available on both sides.	Marginal due to SCA

[a] Electrostatic precipitator (ESP) specific collection area (SCA) in terms of square feet of plate area per 1000 actual cubic feet per minute (acfm).

1.4 COAL SWITCHING (CS) AND PHYSICAL COAL CLEANING (PCC)

To estimate the cost of CS, the simplified procedures used one of the two low sulfur base coals contained in the IAPCS cost model. One of the coals is a low sulfur West Virginia bituminous coal and the other is a Montana subbituminous coal. The currently used coal characteristics and cost are input to the model, and the model estimates the cost of CS based on the user specifying the fuel price differential between the current coal and the future price of one of the two low sulfur base coals. Future coal price differentials of \$5 and \$15/ton were input to the model to span the range of possible low sulfur coal prices over high sulfur coals.

IAPCS cost estimates also include the cost of ESP upgrades and changes in waste disposal costs due to differences in coal ash content. The model does not evaluate the impact of CS on the following boiler operating parameters: pulverizer capacity, slagging, fouling, erosion, and flue gas flow rates. Also, costs for additional coal receiving, storage, and handling facilities are not included. These factors are discussed qualitatively for each plant and boiler situation.

Under this effort, the primary objective was to obtain additional information from the six plants visited to better identify and quantify boiler and plant parameters that would be negatively impacted by CS. Table 1-6 summarizes the results of this effort. As can be seen, the only major issue identified was switching to a subbituminous coal at the Sioux plant. The low sulfur subbituminous IAPCS base coal option was chosen because the plant currently uses a low sulfur subbituminous coal. The procedure methodology assumes that the base coal should be similar to the low sulfur coals currently being used by the plant. However, completely switching a boiler designed to fire a bituminous coal to a subbituminous coal would result in a major unit derate.

Currently, the CS methodology does not quantitatively address capital costs associated with coal receiving, storage, and handling facilities that may be required to blend coals on-site or to bring coal in by a different transportation method. For the Labadie plant, the cost to upgrade its facilities to blend coals was on the order of $22.5 million (1987 dollars). However, the cost of upgrading facilities would typically be much less than a $5/ton impact on the coal fuel price differential.

Based on the six plant evaluation of the simplified procedures, a more careful approach should be made in evaluating CS to subbituminous coals on boilers designed for firing bituminous coals. In general, the following guideline should be observed: boilers designed for bituminous coals will continue to burn the same percentage of bituminous coal as currently is being fired.

Due to the lack of coal washability data, it has not been possible to evaluate quantitatively the cost of deep PCC. As such, the costs generated under this study are very qualitative. However, no feedback has been given to date regarding the costs and percent removals projected with the current methodology.

TABLE 1-6. SUMMARY OF COAL SWITCHING ISSUES

Plant Name	Units	Coal Switching and Blending Issues
Sioux	1 - 2	Minor boiler derate up to 40% SB[a], major derate >50% SB.
Labadie	1 - 4	Switch coal may reduce severe slagging problems at high load but will increase ash disposal costs. Switching could also increase slagging problems and cause unit derates.
Rush Island	1 - 2	Low SO_2 emission reduction potential. No on-site facilities for blending.
Meramec	1 - 4	Low SO_2 emission reduction potential. No on-site facilites for blending.
Beckjord	1 - 6	Low sulfur coal on units 1-4. No on-site blending facilities for units 5-6.
Miami Fort	5 - 7	Compliance coal on unit 8. No on-site blending facilities for units 5-7.

[a] SB = subbituminous.

1.5 SELECTIVE CATALYTIC REDUCTION (SCR)

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for SCR were reviewed for accuracy. The most important parameters that will impact the cost of retrofitting SCR are:

- reactor access and congestion,
- flue gas duct length to and from the reactor, and

- demolition costs of existing equipment and general facilities percentage.

These parameters are impacted by the location chosen for the SCR reactor.

Table 1-7 summarizes the changes made to access/congestion difficulty, scope adder costs, and general facilities percentages due to the site visits for the four Missouri plants. The major problem with the simplified procedures identified by this analysis is one of making the correct location choice based on the information on hand. For the Meramec and Labadie plants, inaccuracies in the available plot plan or the poor resolution of the aerial photograph resulted in incorrectly locating the reactors. For the two Ohio plants, no changes to the reactor locations, duct run lengths, and access/congestion difficulty were needed for Miami Fort. However, for Beckjord units 1-4, the reactor location was changed, resulting in significant increases in duct length.

TABLE 1-7. SUMMARY OF CHANGES MADE TO SCR RETROFIT

Plant Name	Units	Reason for Changes
Sioux	1-2	Scope adder cost changes due to longer duct run.
Labadie	1-4	Change in location of reactor resulted in changes to access/congestion, general facilities, and duct run lengths for all Labadie units.
Rush Island	1-2	No major changes were made to the SCR retrofit compared to the results obtained prior to the site visit.
Meramec	1-4	Changes in location of reactors resulted in significant changes in access/congestion and duct run lengths for all Meramec units.

One option used in the study for several plants has been to call the plant and discuss potential equipment locations. This has been done several times when it was apparent that the quality of the aerial photograph or plot plan was poor. Generally, the plant personnel have been cooperative and, in the future, it may be desirable to contact every plant after reviewing the available data.

1.6 SORBENT INJECTION TECHNOLOGIES

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most important parameters that will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance, and difficulty of upgrade (access/congestion associated with adding plate area),
- need for converting wet ash handling system to a dry handling system, and
- sufficient flue gas residence time between the air heater and particulate control device to allow for duct spray drying (DSD), droplet drying (2 seconds of straight duct run), or humidification with FSI.

The impact of superheat and economizer gas lane pluggage for furnace sorbent injection (FSI) was not evaluated under this program because of the limited commercial demonstration data and boiler information.

Table 1-8 summarizes the results of the changes made to the simplified procedure inputs after the site visits. In general, the overall qualitative determination of the applicability of the sorbent injection technologies was the same before and after the site visit, the major differences being Beckjord units 1-5 and Miami Fort unit 6. These units have small ESP SCAs, and the ducting configuration for units 1-5 was incorrectly interpreted. As a result, because these units have a very short flue gas residence time between the air heater and the ESP inlet and small ESPs, the applicability of any of the sorbent injection technologies is questionable.

TABLE 1-8. SUMMARY OF CHANGES FOR SORBENT INJECTION TECHNOLOGIES

		Applicability Before Visit		Applicability After Visit	
Plant Name and Unit		FSI[a]	DSD	FSI	DSD
Sioux	1-2	Good	Good	Good	Good
Labadie	1-4	Good	Good	Good	Poor to good[b]
Rush Island	1-2	Good	Good	Good	Moderate
Meramec	1-2	Good	Good	Good	Good
	3-4	Good	Good	Poor	Poor
Beckjord	1-5	Good	Poor	Poor	Poor
	6	Good	Good	Very good	Good
Miami Fort	5	Good	Good	Poor	Poor
	6	Good	Poor	Poor	Poor
	7	Good	Poor	Good	Poor

[a] Does not consider superheat/economizer gas line pluggage due to insufficient data.

[b] Part of flue gas bypassed old ESPs resulting in adequate residence time for 50% of gas flow.

With regard to those factors that directly impact the cost estimates, the access/congestion difficulty factor changed for 7 of the 21 units and the wet to dry ash conversion assumption changed for 12 of the 21 units. As discussed previously, the error in the ash conversion assumption was due to a misunderstanding. The EIA-767 forms accurately indicate that the Missouri units currently use wet ash handling/disposal systems.

Based on these findings, it appears that the errors in the procedure methodology are related to incorrectly interpreting the data available. It appears that the publicly available data are sufficient to accurately evaluate the retrofit difficulty of the sorbent injection data for most plants. However, as mentioned earlier, contacting the plant to verify the accuracy of this data and to confirm the accuracy of basic assumptions should reduce the potential for incorrectly interpreting the available data. This is particularly true for small, older units because of the resolution of the photograph and the likelihood that unusual ESP flue gas configurations exist due to the retrofit of additional ESP plate area. The Beckjord units 1-5 and Miami Fort unit 6 are good examples of the problem associated with unusual flue gas configurations due to the retrofit of additional ESP plate area. Additionally, a Department of Energy database containing duct and flue gas information upstream of the ESP has been made available to this study.

1.7 CONCLUSIONS

Based on the six-plant evaluation effort to verify the accuracy of the simplified procedures, the following changes to the procedures were made:

1) After receiving the publicly available information, identifying the equipment layouts, and selecting inputs to the simplified procedures to develop retrofit factors and scope adder costs, the plant was contacted to confirm the accuracy of the data and assumptions.

2) To continue to verify the accuracy of the procedures and cost estimates generated, the plant evaluation and cost estimates were made available to the plant for review and comments. Appropriate

comments and comparative cost estimates were incorporated into the report. Additionally, where actual costs of retrofit are available, these costs were compared to estimates generated using the simplified procedures.

3) Evaluation of retrofitting LSD-FGD was eliminated for units that have marginally sized ESPs (SCA = 225-300) and do not have space for plate area addition.

4) Evaluation of PCC was eliminated except for mine mouth plants with moderate to high sulfur coal, because the emission reductions that are achievable are low, and insufficient data are available to accurately estimate deep coal cleaning costs.

5) Because the current CS methodology assumes total switching to a low sulfur coal, units designed to fire bituminous coals were not switched to a subbituminous coal unless the plant indicates that this is a reasonable option and the cost of unit derate is included in the cost of CS.

6) Hot side SCR was evaluated for units that have space near the boiler.

7) Evaluation of retrofitting FSI and DSD technologies were eliminated for units that have marginally sized ESPs (SCA = 225-300) and do not have space available for plate area addition and sufficient space between the air heater and particulate control device to allow for DSD droplet drying or humidification with FSI.

Making these changes to the simplified procedures improved the accuracy of the cost estimates, ensure continued feedback from industry regarding the accuracy of the procedures/estimates, and eliminated the evaluation of technologies that are not likely to be used, that have limited SO_2 reduction potential, or those for which insufficient data are available to accurately develop cost and performance estimates.

1.8 REFERENCES

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2. Hollinden, G.A. Tennessee Valley Authority, letter to N. Kaplan, U.S. EPA, August 22, 1989.

SECTION 2

COST ESTIMATION PROCEDURES FOR RETROFIT OF SO_2 AND NO_x CONTROLS

This report documents results of a study conducted under NAPAP by the U.S. Environmental Protection Agency (EPA) Air and Energy Engineering Research Laboratory (AEERL). The objective of this study is to significantly improve the accuracy of engineering cost estimates used to evaluate the economic effects of applying SO_2 and NO_x controls to existing coal-fired utility boilers.

Because conducting site visits at all 200 power plants was not feasible, the results of the twelve-plant evaluation (1) were used to develop procedures that only required site-specific inputs from aerial photographs and the EIA-767 forms (simplified procedures). The primary difference between the detailed procedures and the simplified procedures, other than the information detail, is that the procedures for estimating L/LS and LSD-FGD costs (2) were significantly streamlined. This was done to reduce the amount of inputs from over 75 to less that 10 for each FGD option evaluated. The procedure for the other technologies were not significantly changed. The simplified procedure cost/performance inputs focus on those parameters found to have the greatest effect on cost and performance, as summarized in Table 2-1.

Under the second phase of the project, the simplified procedures were used to develop cost/performance estimates for 50 plants. To determine the accuracy of the procedures, each utility company was asked to review and comment on the plant section(s), and at six plants site visits were conducted. This report section discusses the comparison of the IAPCS cost model (3) inputs developed using the simplified procedures (aerial photograph and EIA-767 forms) and the detailed procedures based on the six site visits. The verification effort did not include an evaluation of the LNC and NGR technologies.

TABLE 2-1. RETROFIT COST AND PERFORMANCE INPUTS TO IAPCS MODEL

		Retrofit Factors Addressed			Scope Adders Addressed			
Control Technology	Performance Estimates[a]	Access and Congestion	Underground Obstructions	Process Area Distance	Chimney or Liner	Demolition and Relocation	Additional Particulate Control	Wet to Dry Ash Handling
L/LS-Flue Gas Desulfurization		X	X	X	X	X		X
Lime Spray Drying	X	X	X	X	X	X	X	X
Coal Switching							X	
Physical Coal Cleaning							X	
Furnace Sorbent Injection	X[b]					X	X	X
Duct Spray Drying	X[b]	X			X	X	X	X
Low NO_x Combustion								
Natural Gas Reburn								
Selective Catalytic Reduction	X[b]	X	X		X	X		

[a] Made using procedures not include in IAPCS model.
[b] For particulate control retrofits.

Based on the verification results, modifications were made to the simplified procedures. The modified procedures were then used to develop cost/performance estimates for 188 plants in the final project phase. Table 2-2 compares the differences between the detailed and simplified FGD procedures. The economic premises were based on the 1986 Technical Assessment Guide (4).

2.1. LIME/LIMESTONE AND LIME SPRAY DRYING FLUE GAS DESULFURIZATION

2.1.1 Retrofit Factor Verification

Table 2-3 summarizes the results of comparing the simplified procedure retrofit factors (before and after the site visit) and the detailed procedure retrofit factors for the four Missouri plants visited in this evaluation. As can be seen, the percent difference between the simplified and detailed procedures based on the data obtained from the site visits compare very well. The percent difference for L/LS-FGD varied between -6 and 5 percent with an average of 2.7 percent. The percent difference for LSD-FGD varied between <1 and 5 percent with an average of 1.9 percent. These differences are due to assumptions made when developing the simplified procedures. The procedural differences between the simplified and detailed procedures that resulted are due to the differences presented in Table 2-2.

Table 2-3 also summarizes the differences between the detailed procedures based on site visit data and the simplified procedure results based on publicly available data (before site visit). The percent difference for L/LS-FGD varied from -9 to 16 percent with an average of 8.8 percent. The percent difference for LSD-FGD varied from -24 to 17 percent with an average of 9.8 percent. The difference between results of the two procedures are due to the same factors described above and errors in assumptions due to having less detailed data when applying the simplified procedures with no site visit. The major errors and the reason for making the errors are as follows:

- For all units, it was assumed that the fly ash is handled dry, which was based on a misinterpretation in communications. As a result, costs for wet to dry handling were not included for all

TABLE 2-2. COMPARISON OF L/LS FGD RETROFIT PROCEDURES

Retrofit Parameter	Detailed Methodology	Simplified Methodology
Data Resources	Plant visit/photographs Equipment drawings EIA-767 form verification	Aerial photograph/plot plan EIA-767 form
Process and Location Factors	Developed to estimate retrofit factor	Not applicable
Retrofit Difficulty Multiplier	For all process areas	For SO_2 and flue gas handling
Access/congestion	1.02 to 1.50	1.02 to 1.50
Underground obstruction	1.00 to 1.06	1.03
Distance between process area	1.00 to 1.01	1.0
Flue gas duct distance	Specify length	Select one of five ranges
Scope Adders	Specific $/kW	Average increase to factor
General Facilities	5 to 15 percent	5 to 15 percent
Engineering	10 to 14 percent	10 percent

TABLE 2-3. SUMMARY OF VERIFICATION RESULTS FOR FGD

Plant Name and Unit Number	Percent Difference Relative to Detailed Results[a] Simplified Before Visit	Percent Difference Relative to Detailed Results[a] Simplified After Visit	Detailed Procedure Retrofit Factor
Sioux			
Unit 1 - L/LS-FGD	4	-1	1.36
LSD-FGD	6	1	1.39
Unit 2 - L/LS-FGD	5	-6	1.30
LSD-FGD	3	-2	1.35
Labadie			
Unit 1 - L/LS-FGD	8	5	1.64
LSD-FGD	13	1	1.67
Unit 2 - L/LS-FGD	4	1	1.57
LSD-FGD	13	2	1.82
Unit 3 - L/LS-FGD	11	4	1.59
LSD-FGD	7	3	1.55
Unit 4 - L/LS-FGD	13	1	1.54
LSD-FGD	4	1	1.39
Rush Island			
Unit 1 - L/LS-FGD	-9	-4	1.39
LSD-FGD	-10	-5	1.53
Unit 2 - L/LS-FGD	-15	-5	1.31
LSD-FGD	-24	-1	1.36
Meramec			
Unit 1 - L/LS-FGD	16	3	1.59
LSD-FGD	17	1	1.73
Unit 2 - L/LS-FGD	12	3	1.53
LSD-FGD	12	-4	1.64
Unit 3 - L/LS-FGD	9	0	1.48
LSD-FGD	6	2	1.53
Unit 4 - L/LS-FGD	4	-2	1.39
LSD-FGD	-5	-1	1.37

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[a] [(Detailed procedure - simplified procedure)/detailed procedure] x 100.

units (5). The EIA-767 form correctly indicates that the fly ash is disposed of in a pond and indicates that the units have wet handling systems. This error results in a 5 to 10 percent difference.

- For the Sioux plant, the wet to dry ash handling system conversion was the only significant error.
- For the Labadie plant, the duct work distances were generally increased and the access/congestion difficulty was increased from medium to high. This error was caused by incorrectly interpreting the plot plan and aerial photograph.
- For the Rush Island plant, the absorber and flue gas handling area access/congestion difficulty was reduced from high to medium or low depending on the absorber location. This error resulted from incorrectly calculating the area between the chimney and coal pile. After visiting the plant, it was obvious that sufficient space was available behind the chimney and adjacent to unit 2. Recalculation of the area confirmed that, based on EPRI guidelines, the access/congestion difficulty factor should be low.
- For the Meramec plant, the location for the FGD absorbers was changed because the plot plan used did not show the retrofit ESPs behind the unit chimneys. The revised absorber location next to unit 4 resulted in increased duct work distances for units 1, 2, and 3. After the site visit, a high altitude aerial photograph was obtained from the USGS, and this photograph clearly shows the retrofit ESPs located behind the unit chimneys.

Based on these results, it was concluded that the use of EIA-767 form data and USGS photographs can be used to accurately determine the retrofit difficulty for FGD. However, experience is needed to accurately evaluate these sources of information. Additionally, communications with the plant generally can be very helpful in confirming the best location of the FGD process areas and retrofit difficulty issues. Comparison of the simplified procedure results developed before and after the site visits for the two Ohio plants did not change significantly; therefore, a detailed study for these two plants is not presented in this report.

2.1.2 Capital Costs Verification

Once the FGD retrofit factors have been developed, they are input into the IAPCS cost model along with other coal and boiler parameters to generate capital and levelized annual costs. Retrofit factors are applied to the direct capital costs prior to adding indirect costs, allowance for funds during construction, inventory capital, land, and preproduction costs. Because land and preproduction costs are not multipliers of capital costs, a change in the retrofit factor results does not change these components of the capital costs.

Table 2-4 shows the effect of changing the retrofit factor on capital and operating cost estimates. For the two example units presented, the percent difference between the change in retrofit factor and capital costs varied from 1.7 to 2.6 percent for a retrofit factor change of 1.2 to 1.4 and varied from 4.8 to 6.6 percent for a retrofit factor change of 1.2 to 2.0. The change in levelized annual cost is smaller than the change in capital cost because the capital cost is only one component of the levelized annual cost. The remainder of the levelized cost consists of operating and maintenance cost.

Comparison to Utility Cost Estimates--

The capital costs estimated by the simplified procedure were compared to those developed by A&E firms when A&E estimates were available. Tables 2-5 through 2-8 present a detailed comparison of capital costs estimated using IAPCS and costs estimated by A&E firms. Costs for a retrofit wet lime FGD system at Asbury unit 1 in Missouri are presented in Table 2-5. A retrofit factor of 1.31 was applied to this site, yielding a total capital cost of $233/kW from IAPCS. A regional cost factor of 1.13 for the state of Missouri was then incorporated and resulted in a total capital cost of $264/kW. The cost developed by an A&E was $274/kW; thus, the difference was about -3.8 percent. As shown in Table 2-5, the costs for individual items vary significantly. However, this is probably due to different allocation of equipment among the separate items listed. For example, costs for piping and valves, listed as a separate item by

TABLE 2-4. EFFECT OF RETROFIT FACTOR CHANGE ON CAPITAL AND LEVELIZED ANNUAL COSTS

Plant Name (Unit 1)	Generating Capacity (MW)	Retrofit Factor	Percent Change in Retrofit Factor	Capital Cost Estimation ($/kW)	Percent Change in Capital Cost	Levelized Annual Cost (million $)	Percent Change in Levelized Annual Cost
Rush Island	621	1.20		169		36.14	
			17		14		10
		1.40		192		39.76	
			42		35		25
		1.70		228		45.18	
			67		56		40
		2.00		263		50.61	
Meramec	138	1.20		289		10.89	
			17		15		13
		1.40		332		12.35	
			42		37		33
		1.70		397		14.52	
			67		59		53
		2.00		461		16.69	

TABLE 2-5. FGD CAPITAL COST COMPARISON: ASBURY STEAM PLANT[a]

	Unit 1 (213 MW)		
Capital Costs	A&E[b] Cost ($1000)	Generic IAPCS Cost ($1000)	Regional IAPCS Cost ($1000)
Material handling	1,560	1,721	1,945
Feed preparation	2,220	1,766	1,996
Gas handling (ducting)	6,320	2,726	3,080
FGD absorbers	12,370	13,712	15,495
Reheat system	710	3,406	3,849
Waste separation & disposal	5,380	3,033	3,427
Fans	360	3,605	4,074
Piping and valves	3,610	--	--
Electrical control equipment	5,780	--	--
Foundation, structural steel, and enclosures	6,190	--	--
Total direct	44,870	30,014	33,916
Indirect costs	6,730	7,727	8,732
Contingency	6,730	9,191	10,386
Total capital costs	58,330	49,678	56,136
Total capital ($/kW)	274	233	264

[a] 1987 dollars.
[b] Black & Veatch (6).

Black & Veatch, are included in the costs for the process equipment by IAPCS. Therefore, the bottom-line capital costs show a small net percent difference. It should be noted that the accuracy of the IAPCS estimates is generally considered to be ±30 percent.

Table 2-6 presents costs for a retrofit wet limestone FGD system at the Sibley Steam Plant in Missouri. The IAPCS cost estimate was $222/kW, which includes a retrofit difficulty of 1.41 and a regional cost factor of 1.13. The A&E firms estimated a total capital cost of $199/kW, resulting in a percent difference of +11.4. Again, the costs for individual items vary significantly, but the net difference in the bottom-line cost is small.

TABLE 2-6. FGD CAPITAL COST COMPARISON: SIBLEY STEAM PLANT[a]

	Unit 3 (365 MW)		
Capital Costs	A&E[b] Cost ($1000)	Generic IAPCS Cost ($1000)	Regional IAPCS Cost ($1000)
Material handling	750	1,460	1,650
Feed preparation	3,540	3,952	4,466
Gas handling (ducting)	7,140	6,310	7,130
FGD absorbers	10,920	19,130	21,617
Reheat system	4,140	4,702	5,313
Waste separation & disposal	4,800	3,216	3,634
Fans	890	5,116	5,781
Piping and valves	5,430	--	--
Electrical control equipment	5,260	--	--
Foundation, structural steel, and enclosures	11,110	--	--
Total direct	55,970	43,878	49,582
Indirect costs	8,390	10,394	11,745
Contingency	8,390	13,450	15,198
Total capital costs	72,750	71,737	81,063
Total capital ($/kW)	199	197	222

[a] 1987 dollars.
[b] Black & Veatch (7).

Costs for wet limestone FGD systems retrofit on units 1 and 2 at the Thomas Hill Steam Plant in Missouri are shown in Table 2-7. The retrofit factor and regional cost factor for both units were 1.31 and 1.13, respectively. The IAPCS total capital cost for unit 1 was $355/kW compared to Burns & McDonnell's estimate of $363/kW. For unit 2, IAPCS estimated $297/kW, and Burns & McDonnell projected $282/kW. These costs represent differences of -2.1 and +5.6 percent for units 1 and 2, respectively.

Table 2-8 presents costs for retrofit wet limestone FGD systems at New Madrid units 1 and 2 in Missouri. A retrofit difficulty of 1.24 and a regional cost factor of 1.13 were applied to both units. The IAPCS total

TABLE 2-7. FGD CAPITAL COST COMPARISON: THOMAS HILL STEAM PLANT[a]

	Unit 1 (180 MW)				Unit 2 (290 MW)			
Capital Costs	A&E[b] Cost ($1000)	Generic IAPCS Cost ($1000)	Percent[c] Difference (%)	Regional IAPCS Cost ($1000)	A&E[b] Cost ($1000)	Generic IAPCS Cost ($1000)	Percent Difference (%)	Regional IAPCS Cost ($1000)
Limestone preparation equipment	712	1,452	103.9	1,641	1,069	5,106	377.6	5,770
Site preparation	718	--	--	--	1,078	--	--	--
Gas handling (ducting)	5,586	2,786	-50.1	3,148	8,386	3,711	-55.7	4,193
SO_2 absorbers	12,639	14,921	18.1	16,861	17,516	20,349	16.2	22,994
Reheat system	--	3,040	--	3,435	--	3,823	--	4,320
Waste separation	1,070	3,387	216.5	3,827	1,607	3,689	129.6	4,169
Oxidation	772	645	-16.5	729	1,158	841	-27.4	950
Material handling	2,375	2,991	25.9	3,380	3,567	2,991	-16.1	3,380
Fans	--	3,476	--	3,928	--	4,918	--	5,557
Electrical equipment	3,024	--	--	--	3,766	--	--	--
Foundation/substructure	3,766	--	--	--	5,426	--	--	--
Chimney	4,322	--	--	--	--	--	--	--
Painting, miscellaneous	774	--	--	--	1,162	--	--	--
Contingency	7,152	--	--	--	8,947	--	--	--
Total direct	42,910	33,994	-20.8	38,413	53,682	45,497	-15.2	51,412
Indirects	20,897	8,588	-58.9	9,704	26,143	12,095	-53.7	13,667
Contingency	1,502	10,869	623.7	12,282	1,879	14,539	673.8	16,429
Total capital costs	65,308	56,589	-13.4	63,946	81,704	76,331	-6.6	86,254
Total capital ($/kW)	363	314	-13.4	355	282	263	-6.6	297

[a] 1987 dollars.
[b] Burns & McDonnell (8).
[c] (A&E cost - IAPCS cost)/A&E cost * 100.

TABLE 2-8. FGD CAPITAL COST COMPARISON: NEW MADRID STEAM PLANT[a]

	Unit 1 (600 MW)				Unit 2 (600 MW)			
Capital Costs	A&E[b] Cost ($1000)	Generic IAPCS Cost ($1000)	Percent[c] Difference (%)	Regional IAPCS Cost ($1000)	A&E[b] Cost ($1000)	Generic IAPCS Cost ($1000)	Percent Difference (%)	Regional IAPCS Cost ($1000)
Limestone preparation equipment	1,680	6,404	281.2	7,237	1,680	7,305	334.8	8,255
Site preparation	1,617	--	--	--	1,617	--	--	--
Gas handling (ducting)	16,027	6,153	-61.6	6,953	15,329	6,370	-58.4	7,198
SO_2 absorbers	19,579	32,330	65.1	36,533	19,579	32,512	66.1	36,739
Reheat system	--	6,053	--	6,840	--	6,083	--	6,874
Waste separation	3,214	4,291	33.5	4,849	3,214	4,662	45.1	5,268
Oxidation	2,315	1,223	-47.2	1,382	2,315	1,334	-42.4	1,507
Material handling	7,135	3,476	-51.3	3,928	7,135	3,641	-49.0	4,114
Fans	--	9,356	--	10,572	--	9,437	--	10,664
Electrical equipment	8,123	--	--	--	7,530	--	--	--
Foundation/substructure	10,695	--	--	--	9,940	--	--	--
Chimney	12,327	--	--	--	--	--	--	--
Painting, miscellaneous	2,323	--	--	--	2,323	--	--	--
Contingency	17,007	--	--	--	14,132	--	--	--
Total direct	102,042	69,287	-32.1	78,294	84,794	71,344	-15.9	80,619
Indirects	49,694	19,406	-60.9	21,929	41,295	20,771	-49.7	23,471
Contingency	3,571	21,996	515.9	24,855	2,968	22,665	663.7	25,611
Total capitol costs	155,308	117,080	-24.6	132,300	129,057	121,361	-6.0	137,138
Total capital ($/kW)	259	195	-24.6	221	215	202	-6.0	229

[a] 1987 dollars.
[b] Burns & McDonnell (8).
[c] (A&E cost - IAPCS cost)/A&E cost * 100.

capital cost estimate for unit 1 was $221/kW. This cost is 14.8 percent lower than the Burns & McDonnell estimate of $259/kW. By contrast, the IAPCS cost of $229/kW for unit 2 is 6.3 percent higher than Burns & McDonnell's estimate of $215/kW. One reason for the change in percent difference between units 1 and 2 is that the A&E included the total cost of the chimney with the cost for unit 1. Thus, the A&E cost for unit 1 is higher than for unit 2. This is also true for the Thomas Hill units 1 and 2 costs.

Table 2-9 presents the costs for a retrofit wet lime FGD system at the Beckjord units 5 and 6 and Miami Fort units 6 and 7. The percent difference between the Sargent and Lundy (S&L) cost estimates ranged from -20 to 3. Considering the accuracy of the IAPCS costs are on the order of ±30 percent and the S&L estimates are on the order of ±15 percent, this is a very close comparison. A more detailed discussion of this analysis is presented in Section 7.

TABLE 2-9. FGD CAPITAL COST COMPARISON: BECKJORD AND MIAMI FORT STEAM PLANTS[a]

		High Sulfur Coal			
Unit Number	Generating Capacity (MW)	Percent Sulfur	S&L Cost ($/kW)	IAPCS Cost ($/kW)	Percent[b] Difference
Beckjord					
5 + 6	704	5.5	203	202	-1
Miami Fort					
6	175	5.5	276	283	3
7	524	5.5	210	169	-20
6 + 7	699	5.5	228	199	-13

[a] S&L and IAPCS costs based on 1987 dollars.
[b] (S&L cost - IAPCS cost)/S&L cost * 100.

Comparison of IAPCS Cost Estimates to Actual Installed Costs--

A review of the Flue Gas Desulfurization Information System identified 11 retrofit FGD systems that came on-line after 1980. For seven of these units, actual costs reported in EIA-767 forms and aerial photographs were available and were used to compare the simplified procedure cost estimates to actual reported costs. Table 2-10 summarizes the data available for these FGD systems and the reported actual costs.

Currently, FGD system cost estimates have been developed using the IAPCS cost model with retrofit factors developed from the simplified or detailed procedures for the following units: Paradise 1 and 2, Widows Creek 7, Mill Creek 1 and 2, and Four Corners 4 and 5. Table 2-11 summarizes the results of this effort with the actual costs being escalated to the same year dollars as the cost estimates (January 1988).

As can be seen, the cost estimates developed for Four Corners and Paradise compare well with the reported actual costs. However, the cost estimates for the Mill Creek and Widows Creek units differ significantly. The likely reasons for the differences are:

1) Mill Creek units 1 and 2 and Widows Creek units 7 and 8 share common feed and waste handling facilities.

2) The Mill Creek and Widows Creek units were not current state-of-the-technology designs and have undergone significant design changes since start-up.

All of these factors would reduce the actual cost compared to the estimates developed based on current NSPS design. However, despite these differences, the reported costs for Mill Creek 2 and Widows Creek 7 appear to be very low. Note that the most recent FGD system actual costs compare favorably to the IAPCS estimates and that the costs of the more recent units range from $180/kW to $300/kW. Additional comparisons should be made for the units at Cromby, Eddystone, and Mitchell when sufficient data are obtained to conduct the evaluation.

TABLE 2-10. SUMMARY OF ACTUAL RETROFIT FGD COSTS

Plant Name and Unit Number		State	Size (MW)	Startup Date	EIA-767 Costs ($x10^6)	EIA-767 Costs ($/kW)	FGD Type	SO_2 Removal Efficiency (%)
Paradise	1	KY	700	1983	125	178	Limestone FGD	84
	2	KY	700	1983	125	178	Limestone FGD	84
Widows Creek	7	AL	575	1981	57	99	Limestone FGD	80
Mill Creek	1	KY	355	1980	50	141	Lime FGD	85
	2	KY	355	1981	24	68	Lime FGD	85
Four Corners	4	NM	818	1984	239	292	Lime FGD + baghouse	80
	5	NM	818	1984	239	292	Lime FGD + baghouse	80
Cromby	1	PA	150	1982	NA	NA	Magnesium oxide FGD	92
Eddystone	1	PA	354	1982	84	237	Magnesium oxide FGD	92
	2	PA	354	1982	85	237	Magnesium oxide FGD	92
Mitchell	33	PA	300	1982	83	277	Lime FGD	95

TABLE 2-11. COMPARISON OF RETROFIT FACTORS AND ESTIMATED AND REPORTED COSTS

Plant and Unit	Retrofit Factor	IAPCS Estimated Cost ($/kW)	Reported Actual Cost ($/kW)	Absolute Difference (%)
Paradise 1 or 2	1.35	182	187	1
Four Corners 4[a]	1.66	316	303	4
Four Corners 5[a]	1.66	316	303	4
Mill Creek 1	1.26	180	173	4
Mill Creek 2	1.26	180	75[b]	140
Widows Creek 7	1.24	170	121[b]	40

[a] Cost of fabric filters are also included in the FGD cost.
[b] Hollinden (9).

2.1.3 LSD-FGD with Reuse of ESP

As part of the simplified procedure methodology for LSD-FGD, it is assumed that the existing ESP will be used for particulate control at units that have ESPs with a SCA of greater than 220 sq ft of plate area per 1000 acfm of flue gas. This was the case for all of the Missouri plants and for several of the Ohio units. However, for many of these units, reusing the ESP would result in very difficult and lengthy flue gas duct runs from the outlet of the air heater to the spray dryer absorbers and back again to the ESP inlet. For units that have space adjacent to the air heater and ESP, this option is more practical. Table 2-12 presents the ESP SCA and flue gas duct run lengths and access/congestion difficulty for the six plants evaluated.

As can be seen, all of the Missouri and Ohio units, except Meramec 4 and Beckjord 6, are marginal or poor candidates for LSD-FGD with ESP reuse for one reason or another. For those units where access/congestion difficulty is high, the cost of extended unit downtime is not included in the IAPCS costs. Units with marginally sized ESPs (<300 SCA) may have difficulty in achieving good particulate removal performance. For these units, additional costs would be required for ESP performance upgrades and/or operation at reduced load or SO_2 removal efficiency. These costs are

TABLE 2-12. SUMMARY OF LSD-FGD ESP REUSE FACTORS

Plant Name and Unit		ESP SCA[a]	Duct Length (feet)	Access/Congestion Difficulty	Comments
Sioux	1 and 2	268	500-560	Moderate	Marginal SCA; space available at side of unit; reasonable accessibility to existing flue gas ducting.
Labadie	1 and 4	319	400-520	High	Good ESP performance; space available at both sides; access to existing flue gas ducting is difficult.
Labadie	2 and 3	319	700-800	High	Good ESP performance; space not available at sides or behind chimney; access to existing flue gas ducting is very difficult.
Rush Island	1 and 2	279	560-700	Moderate	Good ESP performance but marginal SCA; reasonable access to existing flue gas ducting and space available at one side and behind chimney.
Meramec	1-3	492-522	800-1300	High	Good ESP performance and SCA; long duct runs and difficult access to existing flue gas ducting because space is only available on far side of unit 4 for absorbers.
Meramec	4	545	500	Moderate	Good ESP performance and SCA; moderate duct runs and accessibility to existing flue gas ducting; space available for absorbers at one side of unit.

(Continued)

TABLE 2-12. (Continued)

Plant Name and Unit		ESP SCA[a]	Duct Length (feet)	Access/Congestion Difficulty	Comments
Beckjord	1-4	205-244	1000+	High	For units 1-5, marginal ESPs; very poor access for duct lines.
	5	247	600-1000	High	(see above)
	6	646	100	Low	Good candidate.
Miami Fort	5	354	300-600	High to low	Poor access for duct runs.
	6	205	300-600	Moderate to low	Very small ESP SCA.
	7	275	100-300	Low	Marginal ESP SCA.

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[a] Electrostatic precipitator (ESP) specific collection area (SCA) in terms of square feet of plate area per 1000 actual cubic feet per minute (acfm).

not reflected in the IAPCS cost estimates. Because the cost of extended unit downtime and ESP performance is very unit specific, it is difficult to quantify without extensive analysis.

Another LSD-FGD option for the Meramec units is to demolish the old ESP boxes and some existing duct work, and put the spray dryer absorbers directly upstream of the retrofit ESP boxes. These boxes would still be large enough to obtain good particulate control. This option has the disadvantage of extended unit downtime. However, because units 1-3 are on standby and unit 4 is rarely used, no economic penalty for extended downtime would be likely. The current utilization of these units is a near-term condition and not necessarily reflective of future operations.

2.2 COAL SWITCHING AND PHYSICAL COAL CLEANING

To estimate the cost of coal switching, the simplified procedures used one of the IAPCS base coals as the switch coal. For boilers firing eastern bituminous coals, the switch coal was a West Virginia/Eastern Kentucky low sulfur bituminous coal. For boilers firing subbituminous coals, a Montana subbituminous coal was selected as the switch coal. The IAPCS model assumes that the switch coal costs $5 and $15/ton more than the current coal. Additionally, costs for ESP upgrading using sulfur trioxide (SO_3) conditioning and changes in waste disposal costs due to increases/decreases in ash disposal are included.

Table 2-13 presents the coal characteristics of the IAPCS cost model low sulfur base coals used for CS.

TABLE 2-13. CHARACTERISTICS OF THE IAPCS MODEL LOW SULFUR COALS USED FOR CS

Coal Characteristic	Low Sulfur Bituminous	Low Sulfur Subbituminous
Btu/lb	12,058	8,789
Ash, %	16.6	8.15
S, %	0.89	0.56
H_2O	3.5	25.2

The procedures also identify boiler and plant situations for which the cost of PCC or CS may be understated using the IAPCS cost model. These situations are as follows:

1) Plants that already use extensively cleaned coal are not evaluated for deep coal cleaning.
2) Cyclone and slagging (wet-bottom) boilers are not evaluated for CS because of the difficulties in finding low sulfur bituminous coals that have the proper ash fusion characteristics.
3) Plants that lack proper coal receiving and handling facilities for switching/blending coals are identified.

Although the capital cost for adding new coal receiving and handling facilities is high, these costs generally are less than $5/ton of coal and generally are much smaller than the fuel price differential between the current and switch coal.

PCC was evaluated using the IAPCS coal database option. Using this option, IAPCS searches the database for a coal similar to the current coal using the parameters of sulfur content, rank, and region. The level of CS is provided, and the model uses the cost of cleaning the database coal to the cleaning level specified. The PCC module used is based on the coal cleaning routines contained in the Advanced Utility Simulation Model and the TVA PCC model (10).

2.2.1 Coal Switching Cost Verification

Under the procedure verification effort, the primary objective was to obtain additional information from the six plants visited to better identify and quantify boiler and plant parameters that would be negatively impacted by CS. Table 2-14 summarizes the results of this effort. As can be seen, the only major issue identified was the use of a subbituminous switch coal at the Sioux plant. This IAPCS base coal option was chosen because the plant currently uses a low sulfur subbituminous coal. The procedure methodology assumes that the base coal should be similar to low sulfur coals currently being used by the plant.

TABLE 2-14. SUMMARY OF COAL SWITCHING OPERATING AND COST IMPACTS

Plant Name and Unit		Coal Type		Coal Switching and Blending Issues	
		Current	Switch	Coal Handling	Boiler Operation
Sioux	1 - 2	B and SB	SB	Has on-site facilities for blending.	Minor boiler derate up to 40% SB; major derate >50% SB.
Labadie	1 - 4	B	B	Has on-site facilities for blending.	Switch coal may reduce severe slagging problems at high load but will increase ash disposal costs.
Rush Island	1 - 2	B	B	Does not have on-site facilities for blending.	Switch coal has higher ash and low SO_2 emission reduction potential.
Meramec	1 - 4	B	B	Does not have on-site facilities for blending.	Switch coal has higher ash and low SO_2 emission reduction potential.
Beckjord	1 - 6	B	B	Currently has two separate coal piles and one coal handling system.	Low sulfur coal on units 1-4.
Miami Fort	5 - 7	B	B	Currently has two separate coal piles and one coal handling system.	Low sulfur coal on unit 8.

B = bituminous.
SB = subbituminous.

The Sioux plant was the only plant evaluated to date where subbituminous coal was blended with a bituminous coal and, as such, the subbituminous low sulfur base coal was selected as the switch coal. However, completely switching a boiler designed to fire a bituminous coal to a subbituminous coal would result in a major unit derate. In fact, the Sioux plant loses 15 to 20 percent of its rated capacity when firing 40 percent subbituminous coal. This derate is allowed based on an economic evaluation of alternatives. The plant does have the option to fire 100 percent of the bituminous coal if the capacity is needed because both coals at the plant comply with the state emission limits.

Use of a low sulfur bituminous coal at the Sioux plant as the switch coal may also result in operating problems. The Sioux boilers have cyclone firing and are slagging boilers. Thus, the coal fired must have the proper ash fusion properties. Low sulfur bituminous coals with the proper ash fusion properties are limited in supply and, as a result, the fuel price differential for these coals may be large.

Currently, the CS methodology does not quantitatively address capital costs associated with coal receiving, storage, and handling facilities that may be required to blend coals on-site or to bring coal in by a different transportation method. For the Labadie plant, the cost to upgrade its facilities to blend coals was on the order of $22.5 million (1987 dollars). Typically, the cost of upgrading facilities would be much less than a $5/ton impact on the coal fuel price differential.

Based on the six-plant evaluation of the simplified procedures, a more careful approach should be made in evaluating CS to subbituminous coals on boilers designed for firing bituminous coals. Future use of the simplified procedures will assume that boilers designed for bituminous coals will continue to burn the same percentage of bituminous coal that currently is being fired. Thus, it will be assumed that there will be no further unit derate by burning a low-sulfur bituminous coal.

2.2.2 Physical Coal Cleaning Cost Verification

Due to the lack of coal washability data, it has not been possible to evaluate quantitatively the cost of deep PCC. As such, the costs generated under this study are very qualitative. To date, no feedback has been given regarding the costs and percent removals projected with the current methodology.

It is recommended that estimating the cost of deep PCC should not be evaluated further under this study except at mine mouth plants due to the following factors:

1) The lack of good washability data makes it difficult to quantitatively estimate the cost of PCC.

2) Much of the coal currently being fired at plants is already washed and cleaned to some degree, making it difficult to estimate additional sulfur removal potential and costs without extensive discussions with the coal supplier. Previous contacts with suppliers have resulted in no cooperation in obtaining additional information.

3) The potential emission reductions that can be achieved by deep PCC is small compared to the other technologies being evaluated, especially since much of the coals being fired are already cleaned to some degree.

4) No inputs have been provided by the participating utilities regarding the level of sulfur reduction and costs associated with the estimates developed to date. This makes it difficult to verify the accuracy of the procedures.

2.3 SELECTIVE CATALYTIC REDUCTION

The major equipment items for an SCR system include the catalyst, ammonia system, controls, air preheater modifications or flue gas reheater, ductwork, and fan. The catalyst volume is based on the flue gas flow rate and the required NO_x reduction percentage. The correlation between catalyst residence time (i.e., catalyst volume/flue gas flow rate) and NO_x reduction performance is based on SCR system vendor design data (11). The SCR equipment cost estimates were developed from recent EPRI (12) and EPA (13) studies.

Two SCR system configurations were evaluated and are shown on Figure 2-1. The hot side system configuration requires that the catalytic reactor be placed in the flue gas path after the economizer and before the air heater to take advantage of the high flue gas temperature (600-700^{o}F or 1110-1290^{o}C). The catalytic reactor for a cold side system would be located in the flue gas path just before the flue gas enters the chimney. This system requires that the flue gas be reheated to 600-700^{o}F. Table 2-15 summarizes the pros and cons of the two configurations. Both types of systems are being used in Japan and Germany. For this study, it was assumed that when space was available, the cold side configuration would be used. This configuration minimizes unit downtime and replacement power costs and maximizes catalyst life. This system also lends itself to combining smaller units into one system, thereby obtaining economy-of-scale benefits.

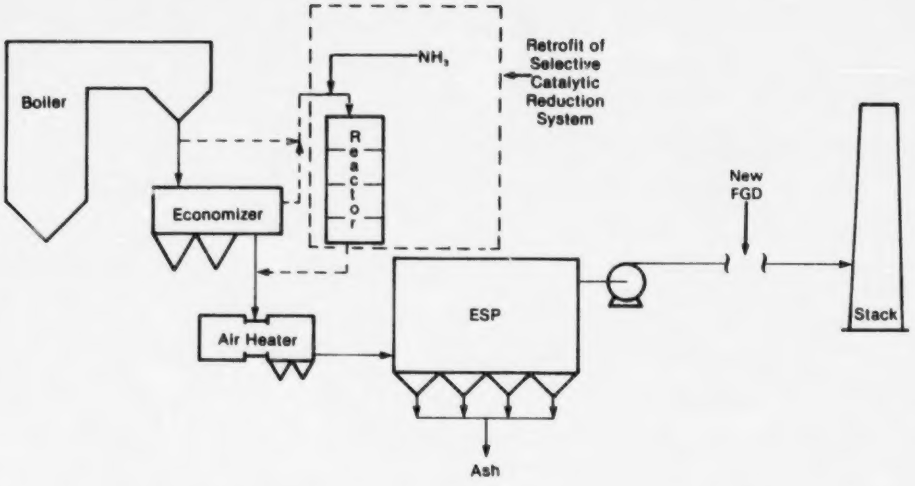
2.3.1 Simplified Procedure Methodology

The method used to develop retrofit factors and scope adders for SCR is similar to the FGD methods. Scope adder costs considered are as follows:

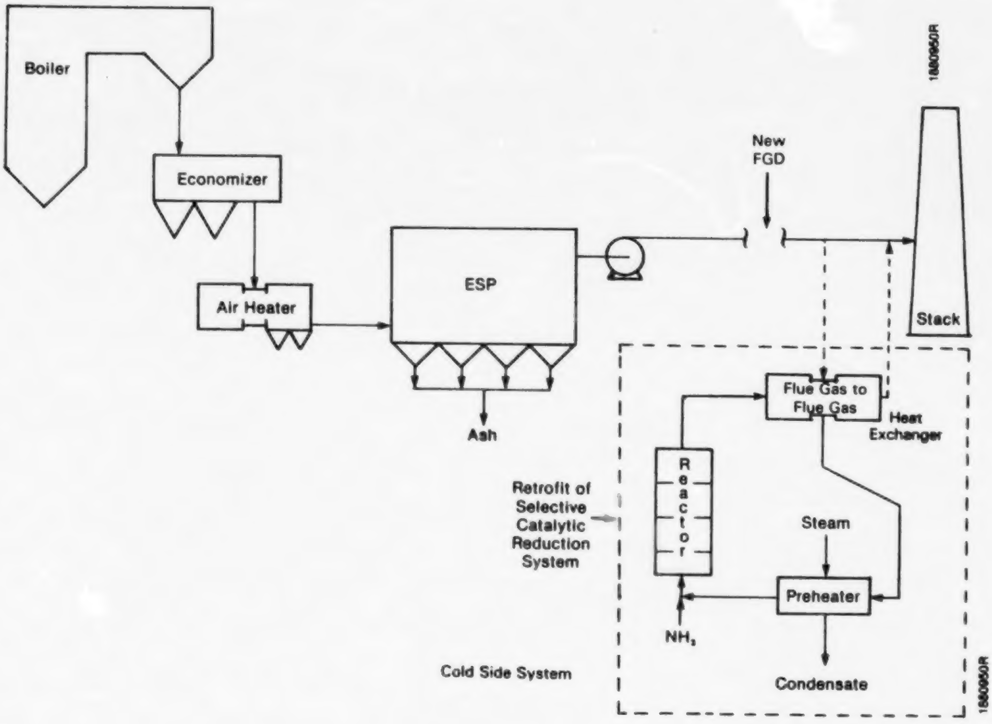
- duct and building demolition,
- new duct work,
- new roads and replacement of demolished facilities, and
- new air heater or flue gas reheater.

The EPRI FGD retrofit guidelines were used to develop costs for the first three items. New roads and replacement of facilities were handled as increases in general facilities. New air heater and flue gas reheater costs are based on a vender quote for a 500-MW plant and scaled by a 0.6 factor (13).

Access/congestion and underground obstruction factors were applied to the catalytic reactor area. The EPRI FGD retrofit guideline factors for the SO_2 and flue gas handling area were used. The scope adder costs and retrofit difficulty factor for each unit were input to IAPCS to generate the site-specific retrofit cost estimates.


Boiler
Economizer
NH3
R e a c t o r
Retrofit of Selective Catalytic Reduction System
New FGD
Stack
ESP
Air Heater
Ash

Hot Side System


Boiler
Economizer
1560950R
New FGD
Stack
ESP
Air Heater
Ash
Flue Gas to Flue Gas
Heat Exchanger
R e a c t o r
Retrofit of Selective Catalytic Reduction System
Steam
Preheater
NH3
Condensate
1560950R

Cold Side System

Figure 2-1. Possible SCR configurations.

TABLE 2-15. TRADE-OFFS ASSOCIATED WITH HOT SIDE/COLD SIDE SCR SYSTEMS FOR COAL-FIRED UTILITY BOILERS

Item	Hot Side System	Cold Side System
Boiler downtime (months)	6-12	1-2
Boiler modifications	Yes	No
Economizer bypass	Yes	No
Air preheater refitting	Yes	No
Precipitator reinforcement	Yes	No
SCR flyash removal	Yes	No
SCR system access/congestion	High	Low to moderate
Catalyst		
Life (hours)	~12,000	~20,000
Type	Honeycomb or plate	Pellet
Catalyst cost	Higher, due to larger volume/ shorter life	Lower, due to less volume/ longer life
Reheat system	No	Yes
Energy penalties		
Reheat	No	Yes
Exchanger pressure drop	No	Yes
Catalyst cleaning air	Yes	No
Combined boiler application	No	Yes
Coarse dust preseparator	Yes	No
Amonia slip	Higher	Lower

2.3.2 SCR Procedure Verification

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adder costs for SCR were reviewed for accuracy. The most important parameters that will impact the cost of retrofitting SCR are:

- reactor access and congestion,
- flue gas duct length to and from the reactor, and
- demolition and relocation costs of existing equipment (general facilities percentage).

These parameters are affected by the location chosen for the SCR reactor.

Table 2-16 summarizes the changes made to access/congestion difficulty, scope adder costs, and general facilities percentages due to the site visits. For two of the plants, the SCR reactor location was not changed, which resulted in no significant changes. However, for the Labadie and Meramec plants, the reactor location was changed and resulted in significant changes to the access/congestion difficulty and scope adder costs. The scope adder cost changes are due to increased flue gas duct run lengths. Althouth cold side SCR systems were evaluated for both the Labadie and Meramec plants, a hot side SCR system may be preferable. At Labadie, there is not sufficient space behind or to the side of units 2 and 3 to put the SCR reactor, which results in the reactor being located at the side of unit 1 or 4. Although this results in lower access/congestion, the flue gas duct runs are quite long. This is also the case for Meramec units 1-3. Installation of the SCR reactors near the air heaters would be difficult at Labadie due to high access/congestion difficulty. However, this would not be the case at Meramec. Extended downtime (3-6 months) would be required to build and tie-in the reactors and duct work. This would not be a problem at Meramec but would be quite costly at Labadie if replacement power costs are more expensive than Labadie's power costs.

The problem with the simplified procedures identified by this analysis is one of making the correct location choice based on the information on hand. For the Meramec and Labadie plants, inaccuracies in the available

TABLE 2-16. SUMMARY OF CHANGES MADE TO SCR RETROFIT

Plant Name and Unit		Changes Made After Site Visits			Reason for Changes
		Access/Congestion Multiplier	Scope Adder Costs ($/kW)	General Facilities (%)	
Sioux	1	NC	6.4	NC	Longer duct run.
Sioux	2	NC	1.0	NC	Longer duct run.
Labadie	1	1.34 to 1.52	3.9	13 to 25	Change in location of reactor resulted in changes to access/congestion and duct run lengths for all Labadie units.
Labadie	2	1.16 to 1.52	10.7	13 to 25	
Labadie	3	1.34 to 1.52	9.2	13 to 25	
Labadie	4	1.34 to 1.16	8.1	13 to 25	
Rush Island	1-2	NC	NC	NC	
Meramec	1	1.52 to 1.16	42	NC	Changes in location of reactors resulted in significant changes in access/congestion and duct run lengths for all Meramec units.
Meramec	2	1.52 to 1.16	34	NC	
Meramec	3	1.34 to 1.16	17	NC	
Meramec	4	1.34 to 1.16	5.2	NC	

NC = no change.

plot plan or the poor resolution of the aerial photograph resulted in incorrectly locating the reactors. One option used in the study for several plants has been to call the plant and discuss potential equipment locations. This has been done several times and generally the plant personnel have been cooperative. To date, this has been done only when it was apparent that the quality of the aerial photograph or plot plan was poor. In the future, it may be desirable to contact every plant after reviewing the available data.

2.4 FURNACE SORBENT INJECTION AND DUCT SPRAY DRYING

These technologies are in various stages of research and development and are being developed specifically for retrofit. As such, many costs of retrofit are built into the base case design and costs. The IAPCS model cost algorithms for FSI with humidification and DSD with calcium-based sorbents were used in this study. The focus of this study was to identify retrofit modifications not covered by the developers. These include particulate control upgrades, conversion of wet fly ash handling systems to dry systems, and demolition/relocation of existing equipment.

Of particular importance to the cost of all technologies will be the ability of the existing particulate control device to be upgraded. The IAPCS model assumes that the benefits of humidification makes all ESPs candidates for reuse. However, numerous boilers have ESPs with SCAs less than the minimum SCA required after humidification estimated by IAPCS. These ESPs are generally old and situated in areas with limited access making plate area addition difficult. Also, many of these boilers have short duct residence time between the air heater outlet and the ESP, making the application of DSD technically infeasible. For these boiler situations, a process being developed by EPA will be applicable for boilers with ESPs in good operating condition.

The process under development, E-SO_x, removes SO_2 along with the particulate matter in an ESP. It is a retrofit process for coal-fired boilers and combines particle collection and spray dryer technology in a single unit. The process uses an existing modified ESP that is equipped with an auxiliary system to prepare and inject a lime slurry into the ESP. E-SO_x produces a dry solid waste that is collected with the ESP fly ash.

Figure 2-2 depicts a schematic diagram of the E-SO_x retrofit. The front end of an existing ESP is converted to a spray chamber for contact of gaseous SO_2 and lime slurry droplets. Because water evaporates within the spray chamber, the reaction product, excess lime, and fly ash that enter the remaining section of the ESP are sufficiently dry for efficient ESP operation. The electrical components of the remaining ESP fields are left intact. To provide adequate space in the contacting chamber for a finite drying time of $\geq$1 second, 25-30 percent of the ESP collecter plate surface may be lost. However, the particulate load will concurrently increase by a factor of three or more, and the particulate, which contains a large calcium-based fraction, has extremely high electrical resistivity. The reaction of lime and SO_2 eliminates the SO_3 effects that have a tendency to lower the resistivity. Alternatively, reducing the gas temperature with the water spray more than compensates for increased resistivity from the ash composition. The availability of advanced ESP technology to help maintain the original particulate collection performance was recognized since the E-SO_x concept originated; e.g., cooled pipe precharging can be added in retrofit ESPs to compensate for reduced collector surface or changes in resistivity.

For all the sorbent injection technologies, access/congestion factors were developed for the sorbent preparation/receiving areas. These factors were not used except for plants where a high value was assumed and this did not occur for any of the plants evaluated under this study. The large project contingency used for these technologies was assumed to adequately cover average access/congestion situations and sorbent conveying distances (500-1500 ft). Retrofit factors and scope adder costs are based on the EPRI retrofit FGD cost-estimating guidelines for the LSD-FGD technology sorbent preparation/flue gas handling process areas and building/duct demolition costs.

2.4.1 Sorbent Injection Procedure Verification

Based on the information obtained during the plant visits, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most

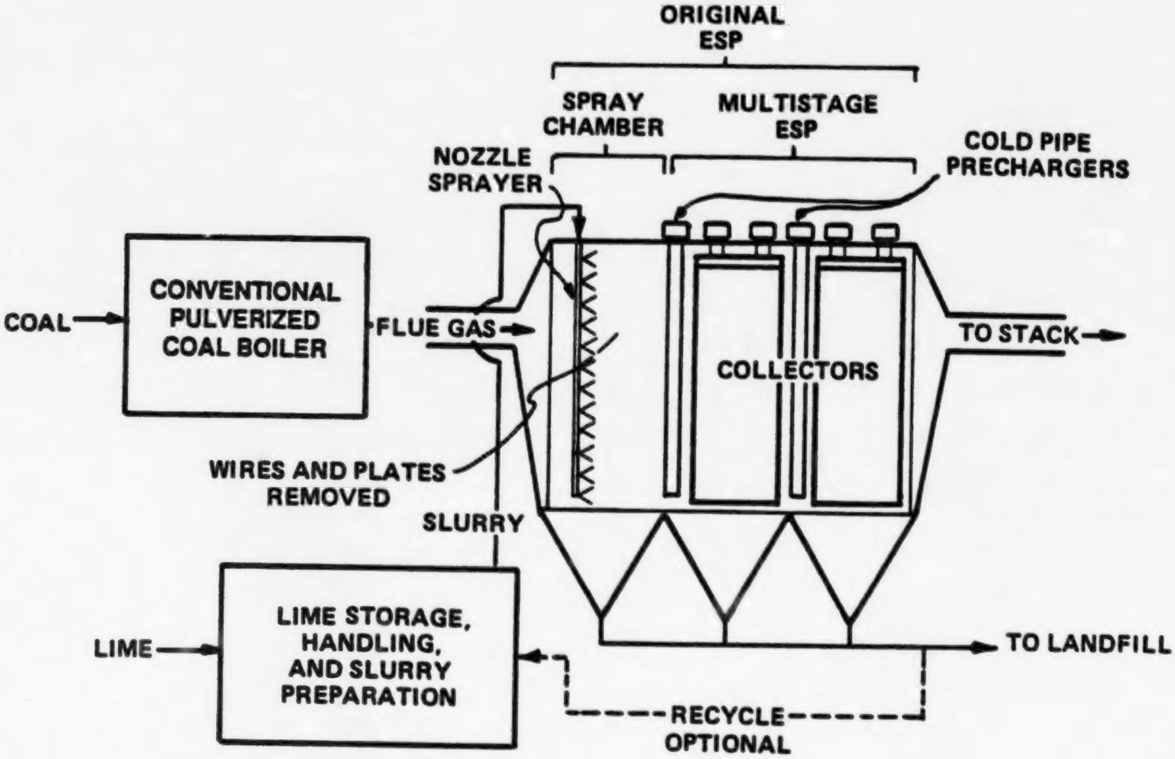

ORIGINAL ESP
SPRAY CHAMBER
MULTISTAGE ESP
NOZZLE SPRAYER
COLD PIPE PRECHARGERS
COAL
CONVENTIONAL PULVERIZED COAL BOILER
FLUE GAS
COLLECTORS
TO STACK
WIRES AND PLATES REMOVED
SLURRY
LIME
LIME STORAGE, HANDLING, AND SLURRY PREPARATION
TO LANDFILL
RECYCLE OPTIONAL

Figure 2-2. Schematic of E-SO_x process (14).

important parameters that will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance, and difficulty of upgrade (access/congestion associated with adding plate area),
- need for converting wet ash handling system to dry system, and
- sufficient flue gas residence time between the air heater and particulate control device to allow for DSD droplet drying (2 seconds of straight duct run) or humidification with FSI.

Table 2-17 summarizes the results of the changes made to the simplified procedure inputs after the site visits. In general, the overall qualitative determination of the applicability of the sorbent injection technologies was the same before and after the site visit, the major difference being Beckjord units 1-5 and Miami Fort unit 6. These units have small ESP SCAs and the ducting configuration for units 1-5 was incorrectly interpreted. Additionally, these units have a very short flue gas residence time between the air heater and the ESP inlet.

With regard to those factors that directly impact the cost estimates, the access/congestion difficulty factor changed for 7 of the 21 units. As discussed previously, the error in the ash conversion assumption resulted from a misinterpretation. The EIA-767 forms accurately indicate that the Missouri units currently use wet ash handling/disposal systems.

Based on these findings, the errors in the procedures were related to incorrectly interpreting the data available. The publicly available data are sufficient to evaluate the retrofit difficulty of the sorbent injection data for most plants. However, as mentioned earlier, contacting the plant to verify the accuracy of this data and to confirm the accuracy of basic assumptions should reduce the potential for incorrectly interpreting the available data. This is particularly true for small, older units because of the resolution of the photograph and the likelihood that unusual ESP flue gas configurations exist due to the retrofit of additional ESP plate area. The Beckjord units 1-5 and Miami Fort unit 6 are good examples of the problem associated with unusual flue gas configurations due to the retrofit of additional ESP plate area.

TABLE 2-17. SUMMARY OF CHANGES FOR SORBENT INJECTION (SI) TECHNOLOGIES

Plant Name and Unit		Changes Made Due to Site Visit							
		Air Heater to ESP Duct Residence Time		ESP Access/Congestion		Ash Handling		Applicability of SI	
		Before	After	Before	After	Before	After	Before	After
Sioux	1	Adequate	Good	Medium	High	Dry	Wet	Good	Good
	2	Adequate	Good	Medium	Medium	Dry	Wet	Good	Good
Labadie	1	Adequate	Poor	Low	High	Dry	Wet	Good	Good for FSI/E-SO_x
	2	Adequate	Poor	Low	High	Dry	Wet	Good	Good for FSI/E-SO_x
	3	Adequate	Poor	Low	High	Dry	Wet	Good	Good for FSI/E-SO_x
	4	Adequate	Poor	Low	Medium	Dry	Wet	Good	Good for FSI/E-SO_x
Rush Island	1-2	Adequate	Poor	Poor to Good	Low to Medium	Dry	Wet	Good	Good for FSI/E-SO_x Moderate for DSD
Meramec	1	Adequate	Good	Medium	High	Dry	Wet	Good	Very good
	2	Adequate	Good	Medium	High	Dry	Wet	Good	Very good
	3	Adequate	Good	Medium	Medium	Dry	Wet	Good	Very good
	4	Adequate	Good	Medium	Medium	Dry	Wet	Good	Very good
Beckjord	1-4	Adequate	Poor	High	High	Wet	Wet	For units 1-5, FSI-good DSD-poor E-SO_x-good	Poor
	5	Adequate	Poor	High	High	Wet	Wet		Poor
	6	Adequate	Good	Low	Low	Wet	Wet	Good	Good
Miami Fort	5	Poor	Poor	High	High	Wet	Wet	For all: FSI-good E-SO_x-good	FSI/E-SO_x-poor
	6	Poor	Poor	High	High	Wet	Wet		Poor
	7	Poor	Poor	Low	Low	Wet	Wet		FSI/E-SO_x-good

2.5 ECONOMIC AND FINANCIAL ASSUMPTIONS

At the outset of the National Acid Precipitation Assessment Program (NAPAP) Task Group I effort, a decision was made to use economic and financial data consistent with accepted industry practices. The accepted standard for the electric utility industry is published in the EPRI's Technical Assessment Guidelines (TAG) (4). The EPRI TAG provides the economic factors and financial data on which the cost estimating procedures used in the electric utility industry are based. Table 2-18 presents the 1986 TAG values. Retrofitting a plant with SO_2 and/or NO_x control technologies with possibly more stringent control limits could cause additional costs for compliance that are not reflected in this study.

The following is a brief overview of the economic and financial assumptions of the EPRI TAG as applied in this stage.

1. Cost-estimating premises adhere to the cost methodology described in Chapter 3 of 1986 EPRI TAG.
2. The indirect capital cost factors were assigned to each technology in accordance with the EPRI TAG. These values were varied in accordance with site-specific conditions and are presented in Table 2-19.
3. Allowance for funds during construction (AFDC) is estimated by adjusting the total plant cost by an allowance factor (AF) that is a function of the idealized construction period and economic parameters.
4. For annual operating costs, the unit costs for consumables per the EPRI TAG are summarized in Table 2-18.
5. Total annual maintenance costs are estimated per the 1986 EPRI TAG as a percentage of installed capital cost depending on the nature of the processing conditions and the type of design. A summary of the factors assigned to the various technologies is presented in Table 2-20.
6. Economic premises for existing electric power generating plants were updated by EPRI and released as a supplement issued

TABLE 2-18. 1986 EPRI TAG VALUES - CAPITAL AND FINANCIAL STRUCTURE

		Current Dollar[a]	
Type of Security	Percent of total	Cost	Return
Debt (Bonds)	50	11.0	5.5
Preferred	15	11.5	1.7
Common stock	35	15.3	5.3
Discount rate, $/yr			12.5
Inflation rate:		6%/yr	
Federal and state income tax rate:		38.0%	
Investment tax credit:		0.0%	
Property taxes and insurance:		2.0%/yr	
Book life		30 yr	

UNIT COST DATA

Item	January 1985 value	Units
Operating labor	19.70	$/person hour
Water (river)	0.60	$/1000 gal
Lime	65	$/ton
Limestone	15	$/ton
Land	6500	$/acre
Disposal Charges		
Sludge	9.25	$/ton (dry basis)
Dry, granular solids	8.0	$/ton
Gypsum disposal	4.75	$/ton
By-Product Credits		
Sulfuric acid	50	$/ton
Sulfur	75	$/long ton
Ammonia (anhydrous)	150	$/ton
Special Items		
Electric power (in plant)	5.0	¢/kWh
Steam (in plant)		
0-70 psia[b]	2.85	$/1000 lb
70-250 psia	3.50	$/1000 lb
250-2400 psia	5.30	$/1000 lb
LEVELIZATION FACTORS		
O&M		1.75
Carrying charges, %		17.5

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[a] For constant dollars, inflation rate is set to zero.

[b] psia (lbs/square inch absolute) = psig (lbs/square inch gauge) + 14.7.

TABLE 2-19. NOMINAL INDIRECT COST SCHEDULE

Indirect Component[a]	PCC	LNC	FSI	NGR	SCR	LSD	DSD	ESP	FF[b]	FGD
General facilities, %	0	10	10	10	10	10	10	10	10	10
Engineering and home office fees, %	0	10	10	10	10	10	10	10	10	10
Project contingency, %	0	30	30	30	30	30	30	30	30	30
Process contingency, %	0	10	20	10	20	4.3	30	0	0	1.4
Sales tax, %	0	0	0	0	0	0	0	0	0	0
Royalty allowance, %	0	0	0	0	0.5	0	0	0	0	0
Preproduction cost[c]	c	c	c	c	c	c	c	c	c	c
Inventory capital[d]	d	d	d	d	d	d	d	d	d	d
Initial catalyst[e]	0	0	0	0	0	0	0	0	0	0
Idealized construction period, yr[f]	0	1	1	1	1	3	1	1	1	3

[a] Applied to process capital except as noted.

[b] FF = fabric filter.

[c] 1 month of fixed operating cost
1 month of variable operating cost.
2 percent of total plant investment.

[d] 60-day supply of consumables.

[e] SCR catalyst costs are estimated based on unit size and desired NO_x removal efficiency.

[f] Used for estimating allowance for funds during construction (AFDC).

TABLE 2-20. MAINTENANCE COST FACTORS

	PCC	LNC	FSI	NGR	SCR	LSD	DSD	ESP	FF	FGD
EPRI schedule (percent of total process capital).	0	2	4	2	4	6	6	8	4	8

May 1, 1983. Revised schedules were published for book life, tax life, and levelization factors. For power plants in operation before January 1, 1979, Internal Revenue Service (IRS) Code Section 169 allows 5-year tax depreciation of new identifiable pollution control facilities completed or acquired after December 31, 1982. This depreciation schedule is applied on a straight-line basis. Book life of retrofitted equipment is equal to the years of remaining life of the power plant rounded off to the nearest 5-year increment. All of these items are identical in the 1986 TAG.

7. The financial and economic premises significantly influence the levelization factors calculated for operating and maintenance (O&M) and carrying charges. Using the 1986 guidelines recommended by EPRI--a 12.5 percent discount rate (or weighted cost of capital), 6.0 percent inflation rate (long-term average), 30-year book life (existing facility), and 20-year tax life (straight-line depreciation)--the levelization factors computed for O&M and capital carrying charges are 1.75 and 0.175 for current dollars and 1.0 and 0.105 for constant dollars, respectively.

8. All costs are presented in current and constant dollars (in the current dollars, the effect of escalation due to inflation is accounted for) and reflect June 1988 dollars. Capital costs are escalated using the Chemical Engineering indices. Current dollar costs account for inflation; constant dollar costs do not.

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SECTION 3

SIOUX STEAM PLANT

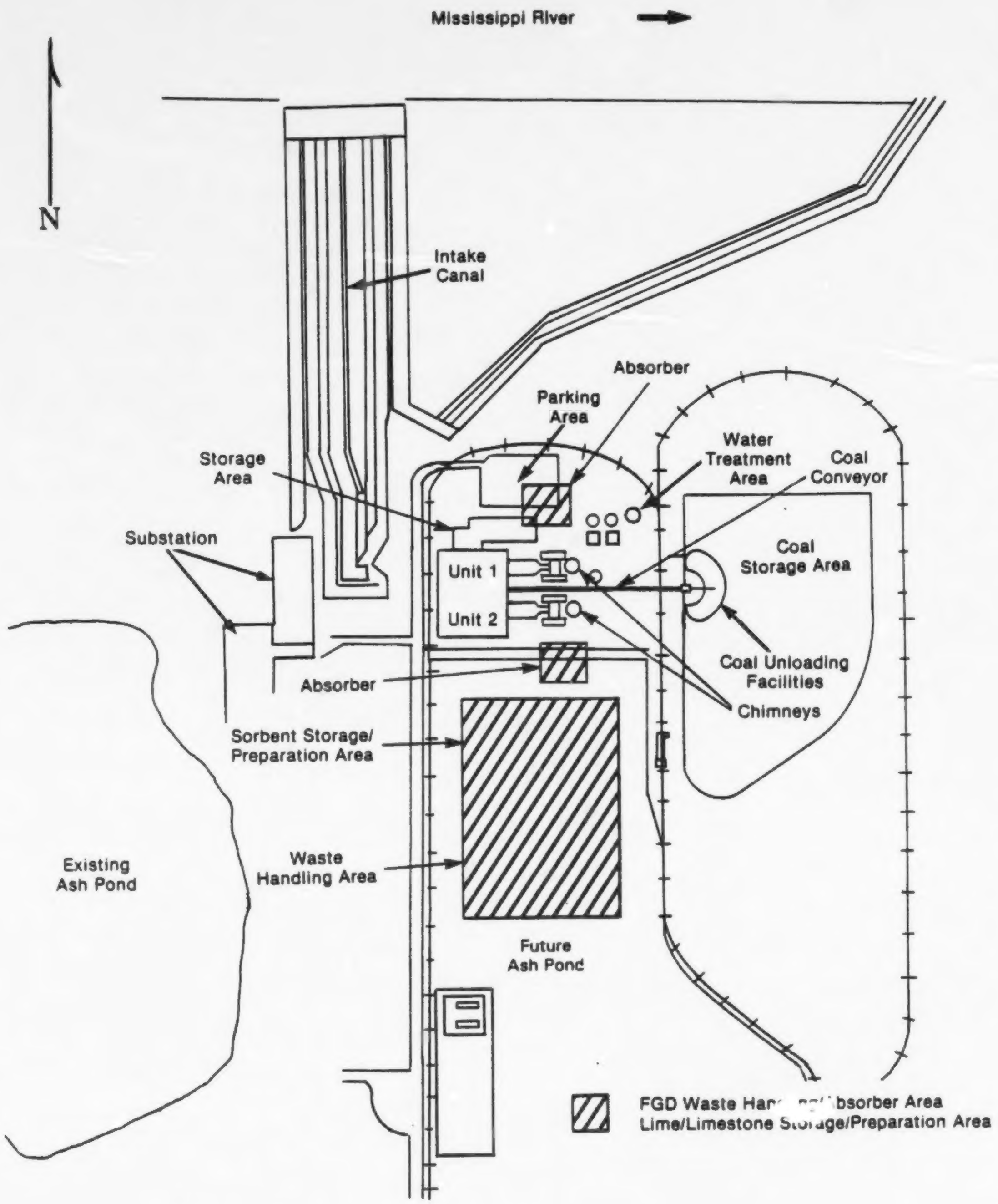
The Sioux steam plant is located along the Mississippi River within St. Charles County, Missouri, as part of the Union Electric Company System. The plant contains two cyclone coal-fired boilers with a total gross generating capacity of 1100 MW. Figure 3-1 shows the location of the two boilers and other plant auxiliary equipment. Table 3-1 presents operational data for the existing equipment at the Sioux steam plant.

Both Sioux boilers burn a medium sulfur coal (1.7 percent sulfur) which is a blend of two types, Illinois high-sulfur and western low-sulfur coals. Coal shipments are received by railroad and are conveyed to a coal storage area east of the plant. Coals are blended, crushed, and conveyed to a surge bin inside the plant. Although the firing of either coal allows the Sioux plant to comply with the state implementation plan for sulfur dioxide emissions, the western coal is cheaper to use. However, when more than 40-50 percent of this coal is used, operating problems result in significant unit derate.

Each unit has a Babcock & Wilcox universal-pressure, cyclone-fired boiler with a furnace volume of 249,820 cubic feet and 1,005°F reheater outlet. Each boiler has ten cyclone burners--five on the front, and five on the back boiler walls. Capacity factors used to analyze the cost of individual technologies for units 1 and 2 were 43.2 and 32.8 percent, respectively. However, capacity factors in the future are expected to increase. Current plant emission rates based on the blended coals for SO_2 and NO_x are 4.4 and 1.5 lb per million BTU, respectively.

Particulate matter emissions are controlled with ESPs located behind each boiler unit. Fly ash from both units is sluiced to ponds southwest of the plant.

Each unit is served by its own chimney located between the ESPs and coal storage and handling area. Chimneys are 600 feet in height and are constructed of reinforced concrete with a corten steel liner.


Mississippi River
N
Intake Canal
Absorber
Parking Area
Water Treatment Area
Coal Conveyor
Storage Area
Substation
Unit 1
Unit 2
Coal Storage Area
Coal Unloading Facilities
Chimneys
Absorber
Sorbent Storage/ Preparation Area
Existing Ash Pond
Waste Handling Area
Future Ash Pond
▨ FGD Waste Han ng/ bsorber Area
Lime/Limestone Storage/Preparation Area

Not to scale

Figure 3-1. Sioux Plant plot plan.

TABLE 3-1. SIOUX STEAM PLANT OPERATIONAL DATA

Item[a]	Units 1-2
Boiler and Stack Data	
Gross generating capacity (MW)	550
Boiler manufacturer	Babcock & Wilcox
Installation data	1967 & 1968
Capacity factor (percent)	43.2,32.8
Boiler type/firing type	Cyclone
Boiler bottom type	Wet
Burner type	Cyclone
Total number of burners	10
Number of burner rows	2
Number of burners per row	5
Nose/top burner row (ft.)	72
Excess air (percent)	23
Flue gas flow rate (10^3 cfm)	830
Slagging/fouling	No
Operating mode (Baseloaded, Intermediate, Peaking)	Intermediate
Stack Number	1-2
Fuel Data	
Heat content (BTU/lb)	11245
Volatile matter (percent)	33.6
Ash (percent)	7.1
Moisture (percent)	19.4
Sulfur (percent)	1.7
Fixed carbon (percent)	43.2
Coal delivery method	Railroad

(Continued)

TABLE 3-1. (CONTINUED)

Item[a]	Units 1-2
Particulate Control Equipment Data	
Type of control	ESP
Installation date (ESP upgrade)	1973
Emissions (lb/MMBTU)	.08
Emission standard (lb/MMBTU)	0.12
Removal efficiency	98.5
Design specification	
Sulfur specification (percent)	3.5
Surface area (1000 ft^2)	536.4
Gas exit rate (1000 ACFM)	2000
SCA (ft^2/1000 ACFM)	268
Outlet temperature (^oF)	350
Fly ash disposal method	Wet/On-site

[a] Based on 1987 data.

3.1 L/LS-FGD RETROFIT DIFFICULTY FACTORS AND COSTS

3.1.1. Lime/Limestone FGD and Lime Spray Drying FGD Layouts

Figure 3-1 shows the general layout and location of the FGD control system. Unit 1 absorbers for L/LS-FGD and LSD-FGD are located to the northwest of the water treatment area, in the existing employee parking lot and storage area, and to the northeast of unit 1 itself. Sufficient space is not available for absorber placement behind the unit 1 chimney due to the existing water treatment area. Placement of absorbers in this area would require major demolition and relocation costs. The absorbers for unit 2 are located to the southeast of unit 2 and to the south of its respective chimney/ESPs, in an area which previously had been designated for a future ash pond.

In the placing of the unit 1 absorbers, relocation is necessary for part of the parking lot and storage area. As a result, a factor of 8 percent has been assigned to general facilities. However, no major demolition/relocation is needed for unit 2 and a base factor of 5 percent consequently has been assigned to general facilities. The L/LS storage/preparation and waste handling areas are located south of unit 2 directly adjacent to the unit 2 absorbers. To the south of unit 2 is the area for the future ash pond. Presently no plans exist for the construction of units on this site and can be used for placement of FGD units. An additional draft booster fan would be installed to overcome the pressure drop of the FGD system. Table 3-2 presents the L/LS-FGD and LSD-FGD cases considered and the anticipated SO_2 removal.

3.1.2 Retrofit Difficulty and Scope Adder Costs

This section presents the results of using the EPRI detailed retrofit FGD cost estimating procedures used to develop retrofit factors for the Sioux plant. The site for unit 1 northwest of the water treatment area in part of the existing parking lot and storage area is a relatively open area with no major obstacle/obstruction. Consequently, a low site access/

TABLE 3-2. SUMMARY OF L/LS-FGD AND LSD-FGD CASES EVALUATED FOR SIOUX PLANT

Case Description	SO_2 Removal (percent)	Coal Sulfur (wt. percent)	Capacity Factor (percent)	SO_2 Reduction (tons per year)
L/LS-FGD				
Boiler 1	90	1.7	43.2	27,680
Boiler 2	90	1.7	32.8	21,016
LSD-FGD				
Boiler 1	76	1.7	43.2	23,467
Boiler 2	76	1.7	32.8	17,817

congestion factor has been assigned to the absorber location. However, due to the close proximity of the absorbers and water treatment area, it is assumed that there are some underground interferences created by the raw and treated water pipes. A medium factor was assigned to the underground obstructions for unit 1 absorbers. For flue gas handling, moderate to long duct runs of 560 feet are required to divert the flue gas from downstream of the ESPs to the absorbers and back to the chimney. A low site access/congestion and medium underground obstruction factor was assigned to the flue gas handling system of unit 1.

The absorber for unit 2 is located in an open area south of unit 2, what is presently the future ash pond site. This area is away from the coal conveyor and coal handling operation as well as chimneys and therefore, longer duct runs are required; the site is spacious and no major demolition/relocation is required. A low site access/congestion factor has been assigned to this location. However, this pond like location has to be filled and raised before it can be used for placing the FGD units. A low factor has also been assigned to the underground obstructions for the unit 2 absorbers. For flue gas handling for unit 2 L/LS-FGD absorbers moderate duct runs of 440 feet are required. A low site access/congestion factor has been assigned to the flue gas handling system.

LSD with reused ESP is the only LSD-FGD technology considered for Sioux plant, since both units presently have moderate SCAs (>260). LSD absorbers are placed in similar locations, as in the case of L/LS-FGD, with similar site access/congestion factors. For flue gas handling, moderate duct runs of 560 feet for unit 1 and 500 feet for unit 2 are required. Reuse of the existing ESPs would require duct runs be made over the existing ESPs and ducting, and a medium site access/congestion factor is assigned to flue gas handling system. The access/congestion factor would be high at the duct tie-in location at the outlet to the airheater and prior to the ESPs. Overall, a moderate access/congestion factor was assigned to the new duct work, since ductwork to and from the LSD absorbers would have low to moderate access/congestion. Tie-in upstream of the ESPs would possibly require lengthy boiler downtime. However, no costs were included for an extended outage, if required. Costs presented in this report do include additional fan capacity needed to overcome the pressure drop due to the additional ductwork and absorbers.

Separate retrofit factors have been developed for upgrading the ESPs. If additional ESP plate area is required, this likely would be tied in after the existing induced draft fans located on either side of the chimney. High site access/congestion and underground obstruction factors have been assigned to the location of the added ESP plate area for unit 1. These factors reflect the limited space availability behind the ESPs which are created by the chimney, water treatment area, unit 2 ESPs, and water pipes. Medium site access/congestion and underground obstruction factors have been assigned to the unit 2 ESP location. These factors reflect the congestion created by the close proximity of the unit 2 ESPs to the respective chimney, coal conveyor, and unit 1 ESPs.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Table 3-3. The largest scope adder for Sioux plant is the conversion of the fly ash conveying system from wet to dry for both boilers. It is assumed that fly ash would be necessary to stabilize the scrubber sludge waste resulting from conventional L/LS-FGD application and to prevent plugging of the sluice lines in LSD-FGD system.

The retrofit factors determined for the L/LS-FGD cases range from 1.29 for unit 2 to 1.36 for unit 1. The retrofit factors for LSD-FGD cases range from 1.35 for unit 2 to 1.39 for unit 1. Tables 3-4 and 3-5 summarize the retrofit factor data for the L/LS-FGD and LSD-FGD technologies.

3.1.3 Simplified Versus Detailed Retrofit Factor Procedure Results

The previous sections present the results of the detailed procedures analysis based on a site visit made to the Sioux plant. In this section, the simplified procedure results made prior to the site visit, and revised after the site visit, are compared with the detailed procedures results.

Prior to the site visit, retrofit factors were developed using simplified procedures based on the following information: a plot plan and EIA form 767. After the site visit, input variables to the simplified procedure were examined (i.e., site access/congestion, scope adders) for

TABLE 3-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR SIOUX PLANT

Scope Adjustment	Description[a]
• Chimney liner	Chimney liner for L/LS-FGD cases for both boilers ($5.58/kW).
• Modify draft controls	Boiler draft control modification/ upgrades were required due to increased pressure drop and added fan capacity ($1.42/kW)
• Demolition and relocation	Relocation of parking lot and storage area for unit 1 absorbers.
• Wet to dry fly ash handling system	To stabilize L/LS-FGD waste and to prevent plugging of the sluice line for LSD-FGD ($7.86/kW).

[a] Costs shown are based on 1987 dollars and have been adjusted for location, process, retrofit, and other considerations.

TABLE 3-4. SUMMARY OF RETROFIT FACTOR DATA FOR SIOUX L/LS-FGD USING DETAILED PROCEDURES

	Boilers	
	1	2
Site Access/Congestion		
Reagent Feed	Low	Low
SO_2 Removal	Low	Low
Flue gas handling	Low	Low
Waste handling	Base	Base
General support equipment	Low	Low
ESP Upgrade	NA	NA
Underground Obstruction		
Reagent feed	Low	Low
SO_2 Removal	Medium	Low
Flue gas handling	Medium	Low
Waste handling	Base	Base
General support equipment	Low	Low
ESP Upgrade	NA	NA
Total Inlet and Outlet Ductwork (ft.)	560	440
Scope Adders		
Chimney liner	Yes	Yes
Draft Controls	Yes	Yes
Wet to dry ash handling system	Yes	Yes
Retrofit Factors		
FGD System	1.36	1.30
ESP Upgrade	NA	NA
General Facilities (percent)	8	5
Engineering and Home Office Fees (percent)	11	10

NA = Not applicable.

TABLE 3-5. SUMMARY OF RETROFIT FACTOR DATA FOR SIOUX LSD-FGD USING DETAILED PROCEDURES

	Boilers	
	1	2
Site Access/Congestion		
Reagent feed	Low	Low
SO_2 Removal	Low	Low
Flue gas handling	Medium	Medium
Waste handling	NA	NA
General support equipment	Low	Low
ESP Upgrade	High	Medium
Underground Obstruction		
Reagent feed	Low	Low
SO_2 Removal	Medium	Low
Flue gas handling	Medium	Medium
Waste handling	NA	NA
General support equipment	Low	Low
ESP Upgrade	High	Medium
Total Inlet and Outlet Ductwork (ft.)	560	500
Scope Adders		
Chimney liner	No	No
Draft controls	Yes	Yes
Wet to dry ash handling system	Yes	Yes
Retrofit Factors		
FGD System	1.39	1.35
ESP Upgrade	1.59	1.34
General Facilities (percent)	8	5
Engineering and Home Office Fees (percent)	11	10

NA = Not applicable.

accuracy. It was not necessary to change the assigned absorber locations or site access/congestion factors. However, longer duct runs are required for unit 2 L/LS-FGD case. For scope adders, costs for conversion of wet to dry ash handling system are also added to all units.

Tables 3-6 and 3-7 present the retrofit factors using the simplified procedure methodology. Table 3-8 presents the retrofit factors developed using the simplified procedure methodology prior to and after the site visit, and the detailed procedure. Since some of the input variables changed, the retrofit factors for L/LS-FGD and LSD-FGD using the simplified procedures change from 5 to 10 percent. The absolute percent differences between the simplified and detailed procedure after the site visit range from 1 to 6 percent for L/LS-FGD and 1 to 2 percent for LSD-FGD.

For both units the differences in retrofit factors for L/LS and LSD-FGD are due to adding the conversion of wet fly ash handling to dry handling. Additionally, the general facilities factor for unit 1 was increased from 5 to 8 percent due to the need for demolition and replacement of storage facilities for placement of the absorbers. The absolute percent differences between the simplified procedure prior to site visit and detailed procedure after the site visit range from 4 to 5 percent for L/LS-FGD and 3 to 6 percent for LSD-FGD. However, since costs of wet to dry ash handling were not included prior to the site visit, these retrofit factors are consistently lower than those generated after the site visit in the detailed procedures.

Retrofit factor differences between the simplified procedures (after the site visit) and the detailed procedures are primarily due to duct length and underground obstruction assumptions. In the simplified procedures, duct length is selected as a range and underground obstruction difficulty is assumed to be moderate. The detailed procedures input a specific duct length and underground difficulty which can vary from base to high. However, for this plant the differences in duct length and underground obstruction are small and result in only a 1 to 6 percent difference.

TABLE 3-6. SUMMARY OF RETROFIT FACTOR DATA FOR SIOUX UNIT 1 USING THE SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

	FGD Technology	
	L/LS-FGD	LSD-FGD
Site Access/Congestion		
SO_2 removal	Low	Low
Flue gas handling	Low	
ESP reuse case		Medium
Baghouse case		NA
Ductwork distance (ft.)	300-600	
ESP reuse		300-600
Baghouse		NA
ESP Reuse	NA	High
New baghouse	NA	NA
Scope Adjustments		
Wet to dry	Yes	Yes
Estimated cost (1,000$)	4,232	4,232
New chimney	No	No
Estimated cost (1,000$)	0	0
Other	No	No
Retrofit Factors		
FGD System	1.38	
ESP reuse case		1.38
Baghouse case		NA
ESP Upgrade	NA	1.59
New Baghouse	NA	NA
General Facilities (percent)	8	8

NA = Not applicable.

TABLE 3-7. SUMMARY OF RETROFIT FACTOR DATA FOR SIOUX UNIT 2 USING THE SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

Item	FGD Technology	
	L/LS-FGD	LSD-FGD
Site Access/Congestion		
SO_2 removal	Low	Low
Flue gas handling	Low	
ESP reuse case		Medium
Baghouse case		NA
Ductwork distance (ft.)	300-600	
ESP reuse		300-600
Baghouse		NA
ESP Reuse	NA	Medium
New baghouse	NA	NA
Scope Adjustments		
Wet to dry	Yes	Yes
Estimated cost (1,000$)	4,232	4,232
New chimney	No	No
Estimated cost (1,000$)	0	0
Other	No	No
Retrofit Factors		
FGD System	1.38	
ESP reuse case		1.38
Baghouse case		NA
ESP Upgrade	NA	1.37
New Baghouse	NA	NA
General Facilities (percent)	5	5

NA = Not applicable.

TABLE 3-8. RETROFIT FACTOR COMPARISONS BETWEEN THE SIMPLIFIED AND DETAILED PROCEDURES

FGD Cases	Simplified Procedure (prior to site visit)	Simplified Procedure (after site visit)	Detailed Procedure	Percent Difference[a]	
				Before[b]	After[c]
L/LS-FGD					
Unit 1	1.31	1.38	1.36	4	-1
Unit 2	1.24	1.38	1.30	5	-6
LSD-FGD					
Unit 1	1.31	1.38	1.39	6	1
Unit 2	1.31	1.38	1.35	3	-2

[a] [(Detailed Procedure-Simplified Procedure)/Detailed Procedure] * 100.

[b] Before site visit.

[c] After site visit.

3.1.4 Summary of FGD Retrofit Costs

Table 3-9 presents the retrofit factors and costs for L/LS-FGD and LSD-FGD cases using the IAPCS cost model. The LSD-FGD costs include upgrading the ESPs for both units.

Application of L/LS-FGD would reduce plant level SO_2 emissions by approximately 71,600 tons per year, assuming a 90 percent level of control. The cost per ton of SO_2 removed ranges from $966 to $1,142.

Application of LSD-FGD would reduce the plant level SO_2 emission by approximately 60,709 tons per year assuming a 76 percent level of control. The cost per ton of SO_2 removed ranges from $696 to $845. The difference in the unit costs is due to the difference in capacity factors for each unit. Unit 1 has a capacity factor of 43.2 percent and unit 2 has a capacity factor of 32.8 percent. Although the LSD reuse ESP costs are less than the L/LS-FGD costs, these costs do not reflect potential downtime costs for LSD-FGD which could be much greater than for the L/LS-FGD system and additional operating costs due to the longer, more difficult flue gas duct runs.

3.2 COAL SWITCHING AND PHYSICAL COAL CLEANING

To estimate the cost of coal switching, the simplified procedures used one of the IAPCS base coals as the switch coal. For the Sioux plant, this coal was a Montana subbituminous coal. For all of the other plants, the switch coal was a low sulfur West Virginia coal. The IAPCS model assumes that the switch coal costs $5 and $15 per ton more than the current coal. Additionally, costs for ESP upgrading using SO_3 conditioning and changes in waste disposal costs due to increases/decreases in ash disposal are included. For the Sioux plant, the Montana coal was selected because the plant already fires 30 to 40 percent western subbituminous coals. However, this amount of coal results in a 10 to 20 percent unit derate. This derate is acceptable because the Union Electric system has sufficient reserve capacity since bringing on line a nuclear unit in 1984. The derate is also

TABLE 3-9. RETROFIT FACTORS AND COSTS FOR L/LS-FGD AND LSD-FGD USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	FGD Retrofit Factor	Particulate Control Retrofit Factor	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
L/LS-FGD	1	43.2	1.36	--	51.4	212.9	1,876.5	51.9	25.0	90	27,680
+ Additive	2	32.8	1.30	--	47.4	201.3	2,223.8	46.7	29.6	90	21,106
LSD-FGD	1	43.2	1.39	1.59	54.3	115.6	1,117.6	26.2	12.6	76	23,467
+ Reuse ESP	2	32.8	1.35	1.34	50.3	109.6	1,346.9	24.0	15.2	76	17,817

allowed based on an economic evaluation of alternatives. The western coal is burned because it is lower in cost than the Illinois coals.

Although firing 30 to 40 percent subbituminous coals does not cause significant operating problems and unit derating, firing 100 percent subbituminous coal would result in major unit derate. As regional power demand grows, it is expected that the capacity factors for both Sioux units will steadily increase making the economic impact of even minor unit derates unattractive. The cost of this derate has not been factored into the cost estimates developed using IAPCS. Modifications to bring the rated capacity of the units back to current levels when firing very high percentages of subbituminous coal can range from $200 to $1,200 per kilowatt of capacity.

Significant unit derates are expected with 50 to 100 percent firing of subbituminous coals on boilers designed to burn bituminous coals. However, because cyclone units are wet bottom boilers, they also require coals having low ash fusion temperatures. This further complicates the types of coals that can be used, the quantity of coal that can be switched, and the price of the coal. Low sulfur bituminous coals having the proper ash fusion properties are available in some of the eastern and western low sulfur coal regions. However, it is likely that these coals will be expensive ($15 per ton and more over the current coal prices) because of the demand and transportation distances.

The Sioux plant does have adequate facilities to blend different coals which is what they now do with the subbituminous and Illinois coals. However, additional equipment may be required for coal blending of more than two coals at this plant. Use of high percentages of very low sulfur coals may require ESP upgrading using SO_3 conditioning or additional ESP plate area. However, these costs have been estimated by IAPCS.

PCC was evaluated using the IAPCS coal database option. Using this option, IAPCS searches the database for a coal similar to the current coal using the following coal parameters: sulfur content, rank, and region. The level of coal cleaning is provided and the model uses the cost of cleaning the database coal to the cleaning level specified. No information was provided by the plant during the visit to better determine the coal cleaning characteristics of the coals currently used. However, it is unlikely that the subbituminous coal would be cleaned and the Illinois coals probably are already being cleaned to some degree. Therefore, achieving a 27 percent SO_2 removal through coal cleaning as estimated by the IAPCS does not seem unreasonable for the Illinois coals.

3.3 SELECTIVE CATALYTIC REDUCTION

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for SCR were reviewed for accuracy. The most important parameters which will impact the cost of retrofitting SCR are:

- reactor access/congestion,
- flue gas duct length to and from the reactor, and
- demolition costs of existing equipment and general facilities percentage.

These parameters are impacted by the location chosen for the SCR reactor. The SCR system type (tail-end) and the reactor location chosen before and after the site visit are the same. Table 3-10 presents the retrofit factors and scope adder costs estimated for the Sioux plant before and after the site visit. The SCR reactor for unit 1 is located north of the ESPs for unit 1 and east of the parking lot in a low congestion area with easy access. The SCR reactor for unit 2 is located south of the ESPs for unit 2 in a low congestion area with easy access. Therefore, both reactors are assigned a low access and congestion factor.

After the site visit, the only changes made to the retrofit factor/scope adder inputs were adjustments to the duct lengths for both units. The duct lengths changed from 300 and 400 feet to 560 and 449 feet for units 1 and 2, respectively.

Table 3-11 presents the estimated costs of retrofitting SCR at the Sioux boilers. Application of SCR would reduce NO_x emissions by 24,155 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed ranges from $2,738 to $3,540. The adjustment in flue gas duct length had a minimal impact on the overall cost of applying SCR at the Sioux boilers.

TABLE 3-10. SUMMARY OF SCR RETROFIT RESULTS FOR SIOUX PLANT

	After Site Visit		Before Site Visit	
Boiler Number	1	2	1	2
Site Retrofit Results				
Site access and congestion				
for SCR reactor	Low	Low	Low	Low
for flue gas handling system	Low	Low	Low	Low
Scope Adder Parameters				
Building demolition(1,000$)	0	0	0	0
Ductwork demolition (1,000$)	97	97	97	97
New duct length (feet)	560	440	300	400
New duct costs (1,000$)	7,558	5,939	4,030	5,373
New heat exchanger (1,000$)	5,184	5,184	5,184	5,184
Total Scope Adder Costs (1,000$)	12,839	11,220	9,310	10,654
Retrofit Factor for SCR	1.16	1.16	1.16	1.16
General Facilities (percent)	13	13	13	13

TABLE 3-11. RETROFIT FACTORS AND COSTS FOR SCR USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor	Scope Cost ($1,000)	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent NO_x Removed	Tons/year NO_x Reduced
SCR	1	43.2	1.16	12,839	88.0	130	1,915.6	26.3	12.6	80	13,731
	2	32.8	1.16	11,220	88.0	127	2,445.9	25.5	16.1	80	10,425

3.4 SORBENT INJECTION

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most important parameters which will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance,and difficulty of upgrade (access/congestion associated with adding plate area),
- need for converting wet ash handling system to a dry system, and
- sufficient flue gas residence time between the air heater and particulate control device to allow for DSD droplet drying (2 seconds of straight duct run) or humidification with FSI.

Based on the EIA 767 form, it was known prior to the site visit that the ESPs had an SCA of 268 and had good removal efficiencies relative to the emission limit of .12 lb/MMBtu. Additionally, it was assumed that the fly ash was disposed of dry and that sufficient duct residence time was available between the air heater and ESP to allow for adequate DSD droplet drying or if not that the ESP was large enough to apply the E-SO_x technology. The E-SO_x technology uses advanced particulate control concepts to enhance the performance of an existing ESP such that the first ESP section can be converted to a spray injection section. This technology is under field pilot scale development at this time.

Based on the site visit, it was learned that the units at Sioux originally had two small ESP boxes in parallel and that additional plate area was later added to improve particulate control prformance while burning lower sulfur coals. Figure 3-2 presents the ESP layout. The additional ESP boxes are located immediately behind the old boxes. Because of the ESP box configuration at the Sioux units, the additional plate area expanded the ESP out to the side of the unit. The Sioux ESPs should be good candidates for retrofit of DSD. Additionally, the old ESP boxes could be converted to spray chambers, and the new boxes could be upgraded using advanced

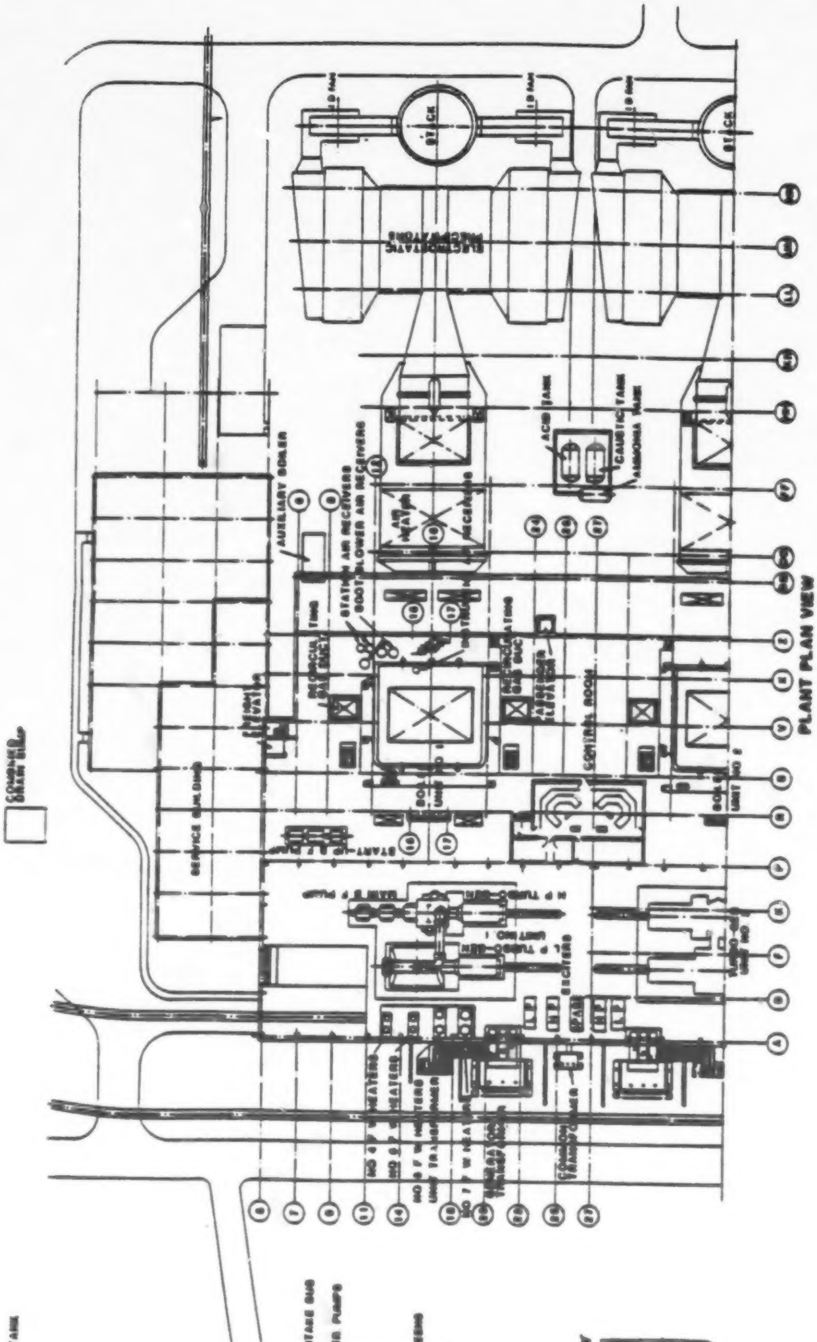

PLANT PLAN VIEW
ELECTROSTATIC PRECIPITATORS
STACK
STACK
ACID TANK
CAUSTIC TANK
AMMONIA TANK
AUXILIARY BOILER
CONTROL ROOM
SERVICE BUILDING
COMBINED DRAIN SUMP
EXCITERS
INTAKE STRUCTURE
TRAVELING SCREENS
CIRC WTR PUMPS
LAYDOWN PLATFORM

Figure 3-2. ESP layout for Sioux Plant

particulate control technology (E-SO_x). Sufficient duct residence time does appear to exist in front of the old boxes to allow for humidification when applying FSI.

It had been assumed prior to the site visit that the access/congestion factor for particulate control upgrading for both units was moderate. However, to add plate area to unit 1 ESPs would be difficult for the following reasons:

- the side by side layout of the units restricts plate area addition beside the inside boxes, and
- there are water treating facilities immediately behind the unit 1 ESP boxes, and a plant road and storage buildings beside the outside ESP box.

Although the actual SCA of the ESPs is 268, it is not likely that additional plate area would be needed for the sorbent injection technologies due to the adequate size of the existing ESPs and the good removal efficiencies currently being achieved.

It was determined by the site visit that the plant uses a wet ash disposal system which would have to be converted to a dry system if any of the sorbent injection technologies were applied at Sioux.

A misunderstanding in communications resulted in assuming that the plant already dry disposed of the fly ash when conducting the simplified procedures before the plant visit. The EIA-767 form clearly indicates that the fly ash is disposed of wet.

Table 3-12 compares the before and after site visit estimates for the retrofit difficulty factors and scope adders for the Sioux units. The difference in the estimate for ESP upgrade access/congestion would not change the costs significantly because significant ESP plate area addition would not be required based on IAPCS ESP performance algorithms. However, addition of costs for converting the wet ash handling system to a dry system will increase capital costs by 20 to 30 percent and annual operating costs by 5 to 10 percent. Table 3-13 presents the revised cost estimates for applying DSD and FSI at the Sioux boilers.

TABLE 3-12. SUMMARY OF DSD/FSI RETROFIT RESULTS FOR SIOUX PLANT

	After Site Visit		Before Site Visit
Boiler Number	1	2	1-2
Site Retrofit Results			
Reagent preparation	Low	Low	Low
ESP upgrade	High	Medium	Medium
New baghouse	NA	NA	NA
Scope Adders			
Change ESP ash discharge system to dry handling	YES	YES	NO
Estimated cost (1,000$)	4,267	4,267	NO
Additional duct work (feet)			
New baghouse case	NA	NA	NA
Estimated cost (1,000$)	NA	NA	NA
ESP reuse case	NA	NA	NA
Estimate cost (1,000$)	NA	NA	NA
Duct demolition length (feet)	50	50	50
Demolition cost (1,000$)	107	107	107
Total cost (1,000$)			
ESP upgrade case	4,374	4,374	107
New baghouse case	NA	NA	NA
Retrofit Factors			
Control system (DSD system only)	1.13	1.13	1.13
ESP upgrade	1.59	1.34	1.34
New baghouse	NA	NA	NA

TABLE 3-13. RETROFIT FACTORS AND COSTS FOR DSD/FSI USING THE IAPCS MODEL

(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor (ESP/FF)	Scope Cost ($1,000)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
DSD + Reused ESP	1	43.2	1.59	4,374	43.2	919.6	13.8	6.6	49	14,963
	2	32.8	1.34	4,374	41.7	1,084.8	12.3	7.8	498	11,361
LIMB + ESP	1	43.2	1.59	4,374	55.6	1,192.4	18.3	8.8	50	15,378
	2	32.8	1.34	4,374	52.6	1,336.4	15.6	9.9	50	11,676

Application of DSD at both units would reduce plant level SO_2 emission by approximately 38,190 tons per year assuming a 48 percent level of control. The cost per ton of SO_2 removed ranges from \$540 to \$642.

Application of FSI at the two units would reduce SO_2 emissions by 39,780 tons per year assuming a 50 percent level of control. The cost per ton of SO_2 removed ranges from \$861 to \$956.

SECTION 4

LABADIE STEAM PLANT

The Labadie steam plant, located 35 miles southwest of St. Louis, Missouri, along the Missouri River within Franklin County, is part of the Union Electric Company system. The plant contains four tangential coal-fired boilers with a total gross generating capacity of 2,482 MW. Figure 4-1 shows the location of the boilers and other auxiliary equipment. Table 4-1 presents the operational data for the existing equipment.

All Labadie boilers burn a 2.5 percent sulfur coal, which is a blend of several Illinois coals. Coal shipments are received by railroad and are conveyed to a coal storage and handling area west of the plant. Coals are conveyed to two surge bins and stored in silos inside the plant from which the coal is fed to pulverizers and then blown into the boilers. By monitoring the SO_2 emissions, the control room operator determines the proper coal blend ratio for each unit.

Each unit has a Combustion Engineering subcritical, tangential-fired boiler with a furnace volume of 428,700 and 422,000 cubic feet for units 1-2 and 3-4, respectively, and a 1,005^{o}F reheater outlet. Each boiler has twenty-four tilting tangential pulverized coal burners mounted in the furnace corners. Capacity factors used to analyze the cost of individual technologies were 59, 52.2, 57.9, and 58.5 percent for units 1 through 4, respectively. However, capacity factors are expected to increase in the future. Current plant emission rates based on the blended coals for SO_2 and NO_x are 4.3 and 0.7 lb per million BTU, respectively. All four boilers have severe slagging problems if operated under full load for more than eight hours and must be cleaned either manually or by pressurized air.

Particulate matter emissions are controlled with ESPs located behind each boiler unit. Retrofit ESPs are added to the existing ESPs behind the chimneys. The ESPs operate in parallel and 60 percent of the flue gases for each unit go to the old ESPs while 40 percent go the the retrofit ESPs. Fly ash from all units is sluiced to ponds located south and west of the plant.

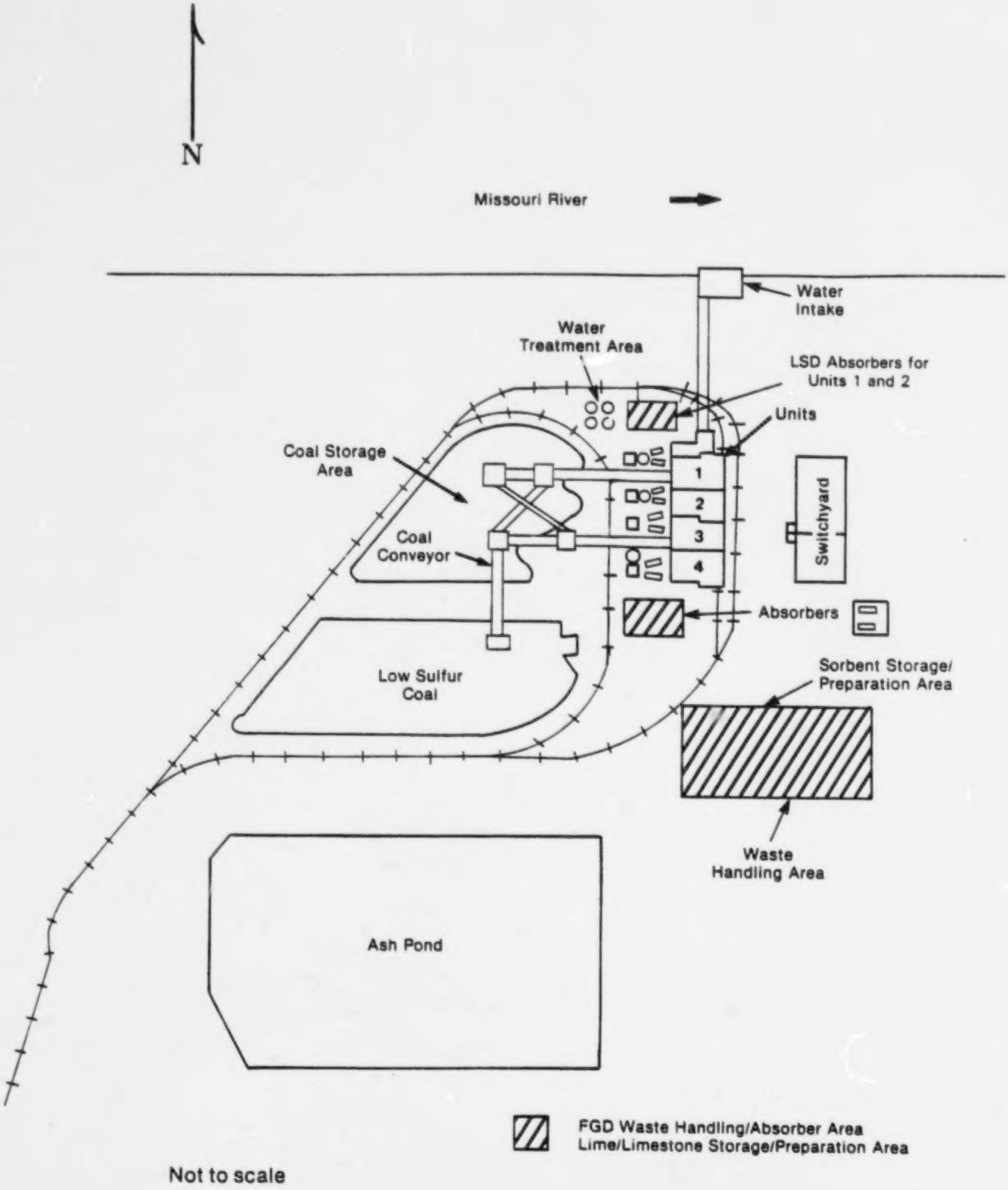

N
Missouri River
Water Intake
Water Treatment Area
LSD Absorbers for Units 1 and 2
Units
Coal Storage Area
1
2
3
4
Switchyard
Coal Conveyor
Absorbers
Sorbent Storage/ Preparation Area
Low Sulfur Coal
Waste Handling Area
Ash Pond
▨ FGD Waste Handling/Absorber Area Lime/Limestone Storage/Preparation Area
Not to scale

Figure 4-1. Labadie Plant plot plan.

TABLE 4-1. LABADIE STEAM PLANT OPERATIONAL DATA

Item	Units 1-4
Boiler and Stack Data	
Gross generating capacity (MW - each)	620.5
Boiler manufacturer	Combustion Engineering
Installation data	1970 - 73
Capacity factor (percent)	59, 52.2, 57.9, 58.5
Boiler type/firing type	Tangential
Boiler bottom type	Dry
Boiler dimensions (D x W x H, ft.)	49.2 x 56.1 x 100
Burner type	Tangential
Total number of burners	24
Number of burner rows	6
Number of burners per row	4
Nose/top burner row	55.5
Burner spacing (vert. x horiz. ft.)	5
Excess air (percent)	23
Flue gas flow rate (10^3 cfm)	1,203
Slagging/fouling	Severe slagging
Operating mode (Baseloaded, Intermediate, Peaking)	Intermediate
Stack number	1-3
Fuel Data	
Coal quality	
Heat content (BTU/lb)	11,346
Volatile matter (percent)	33.6
Ash (percent)	9.0
Moisture (percent)	11.4
Sulfur (percent)	2.54
Fixed carbon (percent)	43.2
Coal delivery method	Railroad

(Continued)

TABLE 4-1. (CONTINUED)

Item	Units 1-4
Particulate Control	
Type of control	ESP
Installation date (ESP Upgrade)	1983
Emissions (lb/MMBtu)	0.009 - .033
Emission standard (lb/MMBtu)	0.12
Removal efficiency	99.4 - 99.8
Design specification	
Sulfur specification (percent)	2.3
Surface area (1,000 sq. ft.)	701.3
Gas exit rate (1,000 ACFM)	2,200
SCA (sq. ft./1,000 ACFM)	319
Outlet temperature (°F)	310
Fly ash disposal method	Wet/On-site

Units 1 and 2 are served by two chimneys, while units 3 and 4 are served by a common chimney located between the old and retrofit ESPs. Chimneys are 700 feet in height and are lined with corten steel liners.

4.1 L/LS FGD RETROFIT DIFFICULTY FACTORS AND COSTS

4.1.1 Lime/Limestone FGD and Lime Spray Drying FGD Layouts

Figure 4-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD for all units are located in an open area south of unit 4 and east of the coal storage handling area. It is necessary for storage areas and the shop building to be demolished in making space available for the FGD units. As a result, a factor of 10 percent has been assigned to general facilities.

In order to be able to reuse the ESPs, LSD absorbers for units 1 and 2 are located northwest of unit 1 beside the water treatment area. A storage building must be relocated and replaced with the absorbers. LSD absorbers for units 3 and 4 are located south of unit 4 with placement being similar to those for the L/LS-FGD controls.

The L/LS storage/preparation and waste handling areas are located south of unit 4 near the absorbers and adjacent to the railroad tracks. An additional draft booster fan is required to overcome the pressure drop of the FGD system. Table 4-2 presents the L/LS-FGD and LSD-FGD cases considered and the anticipated SO_2 removal.

4.1.2 Retrofit Difficulty and Scope Adder Costs

This section presents the results of using the detailed retrofit FGD cost estimating procedures used to develop retrofit factors for the Labadie plant. After demolition and relocation of the storage and shop buildings south of unit 4, a relatively open area with no major obstacle/obstruction is available for the placement of the FGD units. As such, a low site access/ congestion and underground obstruction factor is assigned to the L/LS-FGD absorber location for all units. On the other hand, the lack of space around

Table 4-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR LABADIE PLANT

Case Description	SO_2 Removal (percent)	Coal Sulfur (wt. percent)	Capacity Factor (percent)	SO_2 Reduction (tons per year)
L/LS-FGD				
Boiler 1	90	2.5	59	62,370
Boiler 2	90	2.5	52.2	54,970
Boiler 3	90	2.5	57.9	61,313
Boiler 4	90	2.5	58.5	62,370
LSD-FGD				
Boiler 1	73	2.5	59	52,876
Boiler 2	73	2.5	52.2	46,602
Boiler 3	73	2.5	57.9	51,979
Boiler 4	73	2.5	58.5	52,876

the existing chimney due to the retrofit ESPs and the coal handling area resulted in a high site access/congestion and underground obstruction factor being assigned to the flue gas handling systems. Since units 1 and 2 are in excess of 600 feet from the absorber area (south of unit 4) with high site access/congestion, the cost of a new chimney for units 1 and 2 is included. Interferences with coal handling/blending operation are also reduced by installing a new chimney. Flue gas handling duct lengths range from 650 feet for unit 4 to 900 feet for unit 1.

LSD with reused ESP is the only LSD-FGD technology which is considered, since all units presently have large SCAs (>300). For the LSD-FGD case, a high site access/congestion factor has been assigned to the LSD absorbers for units 1 and 2. This factor reflects the access/congestion difficulty created by the water treatment area and ESPs. It is not economically feasible to demolish and relocate the existing water treatment area. Since the absorbers for units 1 and 2 are located near the water treatment area, a high underground obstruction factor is assigned to the location due to the water pipes. By contrast, the LSD absorbers for units 3 and 4 are located south of unit 4 in the same manner as for L/LS-FGD, where a low site access/congestion factor has been assigned. A medium underground obstruction factor was assigned due to the large underground plant drain pipes. For units 1 and 4, a medium site access congestion factor has been assigned to the flue gas handling system for the following reason. Although it is difficult to reach the upstream side of the old ESP boxes (60 percent of flue gas), it is relatively easy to access the inlet of the retrofit ESP box. As such, an average (medium) congestion factor has been assigned. Access to the unit 2 and 3 ESPs, on the other hand, is extremely difficult and a high site access/congestion factor is assigned to these two units for the flue gas handling systems. Reuse of the units 2 and 3 ESPs would require duct runs to be made over the unit 1 and 4 ESPs. In addition, a high underground obstruction factor has been assigned to all units for the flue gas handling.

The cost penalty for replacement power is not included in the retrofit factors if extensive unit downtime is required for reuse of the existing ESPs. Duct lengths range from 400 feet for unit 1 to 840 feet for unit 3 for the flue gas handling system. Major scope adjustments are presented in

TABLE 4-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR LABADIE PLANT

Scope Adjustment	Description[a]
• New chimney	For L/LS-FGD cases for boilers 1 and 2 ($8.05/kW).
• Chimney liner	Chimney liner for L/LS-FGD cases for boilers 3 and 4 ($6.53/kW).
• Modify draft controls	Boiler draft control modifications/ upgrades were required due to increased pressure drop and added fan capacity ($1.42 kW).
• Demolition and relocation	Relocation of storage area and shop buildings for placement of the FGD units.
• Wet to dry ash handling system	To stabilize L/LS-FGD waste and to prevent plugging of the sluice line in LSD-FGD for all units ($7.76/kW).

[a] Costs shown are based on 1987 dollars and have been adjusted for location, process, retrofit, and other considerations.

Table 4-3. No costs are included for an extended outage, if required, to tie in to the existing duct work between the airheater and the ESPs. However, costs do include additional fan capacity needed to overcome the pressure.

If additional plate area is required, it would be located on the top of the existing ESPs, since no space is available behind the ESPs/induced draft fans. The CS/B area is located behind the ESPs. Therefore, the site access/congestion factor associated with the upgrading of the ESPs would be high due to limited space availability around the existing ESPs.

The retrofit factors determined for L/LS-FGD cases range from 1.54 for unit 4 to 1.64 for unit 1. The retrofit factors for LSD-FGD cases range from 1.37 for unit 4 to 1.82 for unit 2. Tables 4-4 through 4-5 summarize the retrofit factor data for the L/LS-FGD and LSD-FGD technologies.

4.1.3 Simplified Versus Detailed Retrofit Factor Procedure Results

The previous section presents the results of the detailed procedures analysis based on a site visit made to the Labadie Plant. In this section, the simplified procedure results made before the site visit and revised after the site visit are compared with those obtained through using the detailed procedures.

Prior to the site visit, retrofit factors were developed using simplified procedures based on a plot plan and EIA-767 form. After the site visit, input variables to the simplified procedures were examined (i.e., site access/congestion, scope adders) for accuracy. Site access/congestion factors for absorbers were changed from medium to low, because the existing building and storage area can be relocated. This will make space available south of unit 4 for absorbers. After the site visit, it became clear that there is no open space available for tie-in to the existing chimney. This will require building duct runs over the retrofit ESP boxes or demolition of these boxes. Therefore, a high site access/congestion factor is assigned to the flue gas handling system. All cases require medium to long duct runs. Tables 4-6 and 4-7 present the retrofit factors developed using the simplified procedure methodology after the site visit.

TABLE 4-4. SUMMARY OF RETROFIT FACTOR DATA FOR LABADIE L/LS-FGD USING DETAILED PROCEDURES

	Boilers			
	1	2	3	4
Site Access/Congestion				
Reagent feed	Low	Low	Low	Low
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	High
Waste handling	Base	Base	Base	Base
General support equipment	Low	Low	Low	Low
ESP Upgrade	NA	NA	NA	NA
Underground Obstruction				
Reagent feed	Low	Low	Low	Low
SO_2 removal	Medium	Medium	Medium	Medium
Flue gas handling	High	High	High	High
Waste handling	Base	Base	Base	Base
General support equipment	Low	Low	Low	Low
ESP Upgrade	NA	NA	NA	NA
Total Inlet and Outlet Ductwork (ft.)	900	700	800	650
Scope Adders				
New chimney	Yes	Yes	No	No
Chimney liner	No	No	Yes	Yes
Draft controls	Yes	Yes	Yes	Yes
Wet to dry ash handling system	Yes	Yes	Yes	Yes
Retrofit Factors				
FGD System	1.64	1.57	1.59	1.54
ESP Upgrade	NA	NA	NA	NA
General Facilities (percent)	10	10	10	10
Engineering and Home Office Fees (percent)	11	11	11	11

NA = Not applicable.

TABLE 4-5. SUMMARY OF RETROFIT FACTOR DATA FOR LABADIE LSD-FGD USING DETAILED PROCEDURES

	Boilers			
	1	2	3	4
Site Access/Congestion				
Reagent feed	Low	Low	Low	Low
SO_2 removal	High	High	Low	Low
Flue gas handling	Medium	High	High	Medium
Waste handling	NA	NA	NA	NA
General support equipment	Low	Low	Low	Low
ESP Upgrade	High	High	High	Medium
Underground Obstruction				
Reagent feed	Low	Low	Low	Low
SO_2 removal	High	High	Medium	Medium
Flue gas handling	High	High	High	High
Waste handling	NA	NA	NA	NA
General support equipment	Low	Medium	Medium	Medium
ESP Upgrade	High	High	High	High
Total Inlet and Outlet Ductwork (ft.)	400	700	840	520
Scope Adders				
New chimney	No	No	No	No
Chimney liner	No	No	No	No
Draft controls	Yes	Yes	Yes	Yes
Wet to dry ash handling system	Yes	Yes	Yes	Yes
Retrofit Factors				
FGD System	1.67	1.82	1.55	1.39
ESP Upgrade	1.59	1.59	1.59	1.38
General Facilities (percent)	10	10	10	10
Engineering and Home Office Fees (percent)	13	14	12	12

NA = Not applicable.

TABLE 4-6. SUMMARY OF L/LS-FGD RETROFIT FACTOR DATA FOR LABADIE UNITS 1-4 USING THE SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

	Boilers			
	1	2	3	4
Site Access/Congestion				
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	High
ESP reuse case				
Baghouse case				
Ductwork distance (feet)	600-1,000	600-1,000	600-1,000	600-1,000
ESP reuse				
Baghouse				
ESP Reuse	NA	NA	NA	NA
New baghouse	NA	NA	NA	NA
Scope Adjustments				
Wet to dry	Yes	Yes	Yes	Yes
Estimated cost (1,000$)	4,714	4,714	4,714	4,714
New chimney	Yes	Yes	No	No
Estimated cost (1,000$)	4,890	4,890	0	0
Other	No	No	No	No
Retrofit Factors				
FGD System	1.55	1.55	1.53	1.53
ESP reuse case				
Baghouse case				
ESP Upgrade	NA	NA	NA	NA
New Baghouse	NA	NA	NA	NA
General Facilities (percent)	10	10	10	10

TABLE 4-7. SUMMARY OF LSD-FGD RETROFIT FACTOR DATA FOR LABADIE UNITS 1-4 USING THE SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

	Boilers			
	1	2	3	4
Site Access/Congestion				
SO_2 removal	High	High	Low	Low
Flue gas handling				
ESP reuse case	Medium	High	High	Medium
Baghouse case	NA	NA	NA	NA
Ductwork distance (feet)				
ESP reuse	300-600	600-1,000	600-1,000	300-600
Baghouse	NA	NA	NA	NA
ESP Reuse	High	High	High	Medium
New baghouse	NA	NA	NA	NA
Scope Adjustments				
Wet to dry	Yes	Yes	Yes	Yes
Estimated cost (1,000$)	4,714	4,714	4,714	4,714
New chimney	No	No	No	No
Estimated cost (1,000$)	0	0	0	0
Other	No	No	No	No
Retrofit Factors				
FGD System				
ESP reuse case	1.65	1.78	1.50	1.38
Baghouse case	NA	NA	NA	NA
ESP Upgrade	1.59	1.59	1.59	1.38
New Baghouse	NA	NA	NA	NA
General Facilities (percent)	10	10	10	10

Table 4-8 presents the retrofit factors developed using the simplified procedure methodology prior to and after the site visit, along with the detailed procedure evaluations. The absolute percent differences between the revised simplified and detailed procedures range from 0 to 4 percent for L/LS-FGD and 1 to 2 percent for LSD-FGD. Because the access/congestion factor changes for absorbers and flue gas handling area offset each other, the retrofit factors before and after the site visit did not change appreciably. For all units,the differences in retrofit factors for L/LS-FGD and LSD-FGD for the simplified procedures result from the conversion of the wet fly ash handling system to dry.

As Table 4-8 shows, the percent differences between the simplified procedures prior to the site visit and detailed procedures after the site visit are 4-8 percent for units 1-2 and 11-13 percent for units 3-4. By contrast, the percent differences are 13 percent for units 1-2 and only 4-7 percent for units 3-4. The reasons for these percent differences for units 1-2 and 3-4 for LSD and L/LS-FGD cases are as follows: (1) for units 1-2 in the case of LSD-FGD site access/congestion for both SO_2 removal and flue gas handling were changed, while for LSD-FGD, the flue gas handling factor and length were modified; (2) for units 3-4, site acess/congestion for SO_2 removal, flue gas handling, and duct length were modified for both L/LS and LSD-FGD; and (3) for L/LS-FGD, absorbers for all units were placed in one location to the south of unit 4, while absorbers for LSD-FGD were placed to the north of unit 1 for units 1-2 and, for units 3-4, to the south of unit 4. A summary of all percent differences between the simplified and detailed procedures is presented in Table 4-8.

4.1.4 Summary of FGD Retrofit Costs

Table 4-9 presents the retrofit factors and costs for L/LS-FGD and LSD-FGD cases using the IAPCS cost model. The LSD-FGD costs include upgrading the ESPs for all units.

The differences in retrofit factors between the simplified procedures and the detailed procedures after the site visit are primarily due to more input requirements for the detailed procedures. In the simplified procedures, duct length is selected as a range and underground obstruction

TABLE 4-8. RETROFIT FACTOR COMPARISONS BETWEEN THE SIMPLIFIED AND DETAILED PROCEDURES

FGD CASES	Simplified Procedure (Prior to site visit)	Simplified Procedure (After site visit)	Detailed Procedure	Percent[a] Difference before[b]	Percent[a] Difference after[c]
L/LS-FGD					
Unit 1	1.51	1.55	1.64	8	5
Unit 2	1.51	1.55	1.57	4	1
Unit 3	1.41	1.53	1.59	11	4
Unit 4	1.34	1.53	1.54	13	1
LSD-FGD					
Unit 1	1.45	1.65	1.67	13	1
Unit 2	1.58	1.78	1.82	13	2
Unit 3	1.44	1.50	1.55	7	3
Unit 4	1.33	1.38	1.39	4	1

[a] [(Detailed Procedure - Simplified Procedure)/Detailed Procedure] * 100.
[b] Before site visit.
[c] After site visit.

TABLE 4-9. RETROFIT FACTORS AND COSTS FOR L/LS-FGD AND LSD-FGD USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	FGD Retrofit Factor	Particulate Control Retrofit Factor	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
L/LS-FGD	1	59.0	1.64	--	52.4	255.8	1201.8	75	23.4	90	62,370
+ Additive	2	52.2	1.57	--	52.4	246.1	1279.6	70.3	24.9	90	54,970
	3	57.9	1.59	--	52.4	248.9	1193.0	73.1	23.2	90	61,313
	4	58.5	1.54	--	52.4	242	1155.7	72.1	22.5	90	62,370
LSD-FGD	1	59.0	1.67	1.59	57.3	155.5	831.5	44	13.7	76	52,876
+ Reuse ESP	2	52.2	1.82	1.59	58.3	167.9	958.4	44.7	15.8	76	46,602
	3	57.9	1.55	1.59	56.3	145.5	806.1	41.9	13.3	76	51,979
	4	58.5	1.39	1.38	56.3	131.4	748	39.6	12.3	76	52,876

for the flue gas handling system is assumed to be medium. For the detailed procedures, specific duct length and underground obstruction are required. However, as presented in Table 4-8, the estimated retrofit factor differences between the simplified and detailed procedures (after the site visit) are not appreciable.

Application of L/LS-FGD results in a reduction of plant level SO_2 emissions by approximately 239,283 tons per year, assuming a 90 percent level of control. The cost per ton of SO_2 removed ranges from \$810 to \$888.

Application of LSD-FGD results in a reduction of plant level SO_2 emissions by approximately 202,859 tons per year assuming a 76 percent level of control. The cost per ton of SO_2 removed ranges from \$564 to \$749. Differences in unit costs are due to different capacity factors for each unit. Units 1-4 have capacity factors of 65, 57, 61, and 59 percent, respectively. Although the LSD reuse ESP costs are less than L/LS-FGD costs, these costs do not reflect potential downtime costs which can be much greater than for the L/LS-FGD system. This downtime generally occurs where there are more congested and difficult tie-in's to the upstream of the ESPs.

4.2 COAL SWITCHING AND PHYSICAL COAL CLEANING

To estimate the cost of coal switching, the simplified procedures used one of the IAPCS base coals as the switch coal. For the Labadie plant, this coal was a West Virginia/Eastern Kentucky low sulfur bituminous coal. The IAPCS model assumes that the switch coal costs 5 and 15 dollars per ton more than the current coal. Additionally, costs for ESP upgrading using SO_3 conditioning and changes in waste disposal costs due to increases/decreases in ash disposal are included. The following data compares the properties of the coal currently fired at the Labadie plant versus the IAPCS low sulfur bituminous coal.

Coal Parameter	Labadie	IAPCS Coal
HHV - BTU per pound	11,239	12,058
Sulfur - percent	2.5	0.9
Ash - percent	11.6	16.6

The Labadie plant does have adequate facilities to blend different coals, which is what they do now with several Illinois bituminous coals. As such, there would be no additional costs for coal blending at this plant. Use of high percentages of very low sulfur coals is not likely to require significant ESP upgrading. The Labadie plant has an emission limit of 0.12 lb per million Btu, and current emission levels are low (.009 -.033). However, if needed, ESP upgrade costs have been estimated by IAPCS.

One other potentially complicating factor regarding coal switching is that the Labadie boilers have severe slagging problems when operating at full load for more than eight hours. However, most low sulfur eastern bituminous coals have lower slagging potentials than the higher sulfur Illinois bituminous coals. Consequently, slagging is not likely to be worse and may decrease.

PCC was evaluated using the IAPCS coal database option. Using this option, IAPCS searches the database for a coal similar to the current coal using the following coal parameters: sulfur content, rank, and region. The level of coal cleaning is provided, and the model uses the cost of cleaning the database coal to the cleaning level specified. No information was provided by the plant during the visit to better determine the coal cleaning characteristics of the coals currently used. Because the Illinois coals probably are already being cleaned to some degree, only a 27 percent SO_2 removal through additional coal cleaning was estimated by IAPCS.

4.3 SELECTIVE CATALYTIC REDUCTION

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for SCR were reviewed for accuracy. The most important parameters which will impact the cost of retrofitting SCR are:

- reactor access/congestion,
- flue gas duct length to and from the reactor, and
- demolition costs of existing equipment and general facilities percentages.

These parameters are impacted by the location chosen for the SCR reactor. The SCR system type (tail-end) and the reactor location chosen before and after the site visit are the same. Table 4-10 presents the retrofit factors. The SCR reactors for units 1 and 2 are located north of the ESPs for unit 1 and west of the office building in a high congestion area. The SCR reactors for units 3 and 4 are located south of the ESPs for unit 4 and east of the track hopper in a low congestion area with easy access. The arrangements for all units are similar to the LSD-FGD layout; therefore, similar retrofit factors have been assigned. The ammonia storage system has been placed south of unit 4 in a remote area having a low access/congestion factor.

The following site access/congestion factors were adjusted after the site visit. The site access/congestion factors for unit 1 and 2 reactors were changed from medium and low to high, while unit 3 and 4 reactor factors were changed from medium to low. For scope adder parameters, duct lengths are changed from 380, 500, 700, and 500 feet to 400, 700, 800, and 620 feet for units 1-4, respectively. As a result of access/congestion factor adjustments, retrofit factors changed, ranging from 10 to 22 percent. In addition, a low site access/congestion factor previously was assumed as the default for the flue gas handling system. However, duct length costs were corrected, and site access/congestion factors were included in the duct cost estimation. A high site access/congestion factor is assigned to the flue gas handling system due to the congestion around the chimneys (as outlined in the previous sections).

The NO_x control technologies are evaluated independently from the SO_2 control technologies. However, if both SO_2 and NO_x emissions need to be reduced at the Labadie plant, the SCR reactors for all units would be located south of unit 4, downstream from the FGD units. Consequently, a low site access/congestion factor has been assigned to the SCR reactor locations. Short duct runs are required to divert the flue gas from the FGD absorbers to the SCR reactors.

Table 4-11 presents the estimated cost of retrofitting SCR at the Labadie boilers. Application of SCR would reduce NO_x emissions by 32,721 tons per year if 80 percent reduction can be achieved, with the cost per ton of NO_x removed ranging from \$5,161 to \$6,084.

TABLE 4-10. SUMMARY OF SCR RETROFIT RESULTS FOR LABADIE PLANT

	After Site Visit				Before Site Visit			
	1	2	3	4	1	2	3	4
Site Retrofit Results								
Site access and congestion								
for SCR reactor	High	High	Low	Low	Medium	Low	Medium	Medium
for flue gas handling system	High	High	High	High	Low	Low	Low	Low
Scope Adder Parameters								
Building demolition (1,000$)	0	0	0	0	0	0	0	0
Ductwork demolition (1,000$)	106	106	106	106	106	106	106	106
New duct length (feet)	400	700	800	620	380	500	700	500
New duct costs (1,000$)	7,900	13,825	15,800	12,245	5,480	7,211	10,095	7,211
New heat exchanger (1,000$)	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575
Total Scope Adder Costs (1,000$)	13,581	19,506	21,481	17,926	11,162	12,892	15,776	12,892
Retrofit Factor for SCR	1.52	1.52	1.16	1.16	1.34	1.16	1.34	1.34
General Facilities (percent)	25	25	25	25	13	13	13	13

TABLE 4-11. RETROFIT FACTORS AND COSTS FOR SCR USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor	Scope Cost ($1,000)	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent NO_x Removed	Tons/year NO_x Reduced
SCR	1	59.0	1.52	11,162	100.0	152.7	3.846.1	32.8	10.2	80	8,529
3 yr catalyst	2	52.2	1.52	12,892	100.0	162.4	4,472.5	33.6	11.91	80	7,517
life	3	57.9	1.16	15,776	100.0	143.7	3.664.3	30.7	9.7	80	8,385
	4	58.5	1.16	12,892	100.0	137.9	3,531.8	30.1	9.4	80	8,529

4.4. SORBENT INJECTION AND REPOWERING

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most important parameters which will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance and difficulty of upgrade (access/congestion associated with adding plate area);
- need for converting wet ash handling system to a dry system; and
- sufficient flue gas residence time between the air heater and particulate control device to allow for DSD droplet drying (2 seconds of straight duct run) or humidification with FSI.

Based on the EIA-767 form, it was known prior to the site visit that the ESPs had an SCA of 319 and had good removal efficiencies relative to the emission limit of .12 lb/MMBtu. Additionally, it was assumed that the fly ash was disposed of dry and that sufficient duct residence time was available between the air heater and ESP to allow for adequate DSD droplet drying, or if not, that the ESP was large enough to apply the E-SO_x technology. The E-SO_x technology uses advanced particulate control concepts to enhance the performance of an existing ESP such that the first ESP section can be converted to a spray injection section. This technology is under field pilot scale development at this time.

Based on the site visit, it was learned that the units at Labadie originally had two ESP boxes in parallel and that a third box was later added to improve particulate control performance while burning lower sulfur coals. The third box was located behind the chimney of each unit with 40 percent of the flue gas flow being diverted around the original boxes to the third box. As such, the duct residence time to the third box is quite long and the flue gas residence time to the original boxes is quite short. However, the old boxes should be good candidates for the E-SO_x technology because of the reduced flue gas flow rate and overall good particulate removal performance currently being achieved. Figure 4-2 presents the ESP layout at the Labadie plant.

Sufficient duct residence time does appear to exist in front of the old boxes to allow for humidification when applying FSI. However, it had been assumed prior to the site visit that the access/congestion factor for particulate control upgrading was low, when, in fact, it would be difficult for all units. This is due to the following factors:

- the side-by-side layout of the units restricts plate area addition beside the old boxes which is why the new boxes were added behind the chimneys; and
- a railroad track and coal pile are immediately behind the third ESP boxes which also restricts plate area addition to the third boxes.

Although the actual SCA of the ESPs is 319, it is not likely that additional plate area would be needed for the sorbent injection technologies due to the adequate size of the existing SCA and the good removal efficiencies currently being achieved.

It was determined by the site visit that the plant uses a wet ash disposal system which would have to be converted to a dry system if any of the sorbent injection technologies were applied at Labadie. Although the EIA-767 form indicates that the fly ash is disposed of wet, a misunderstanding in communication with the company personnel resulted in assuming that the plant had a dry ash handling system when conducting the evaluation before the site visit.

Table 4-12 compares the before and after site visit estimates for the retrofit difficulty factors and scope adders for the Labadie units. The first major difference is the estimate for ESP upgrade access/congestion which would not change the costs significantly because ESP plate area addition would not be required based on IAPCS ESP performance algorithms. The second major difference is the need to include costs for conversion of the wet fly ash disposal system to a dry disposal system. Adding this cost will increase the capital cost by 20 to 30 percent and the annual cost by 5 to 10 percent. Table 4-13 presents the revised cost estimates for applying DSD and FSI technologies at the Labadie boilers.

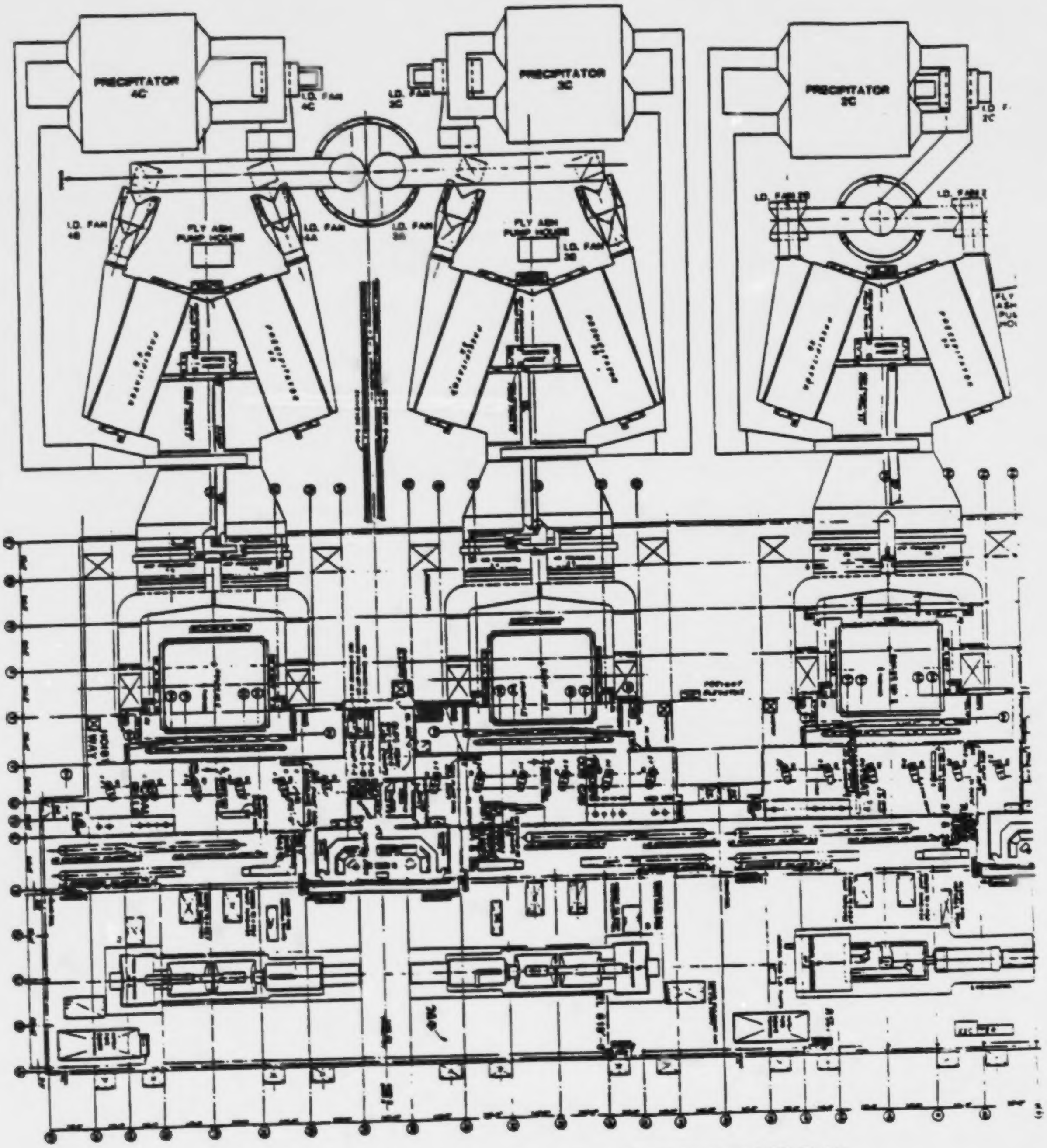

PRECIPITATOR 4C
I.D. FAN 4C
I.D. FAN 3C
PRECIPITATOR 3C
PRECIPITATOR 2C
I.D. F 2C
I.D. FAN 4B
FLY ASH PUMP HOUSE
I.D. FAN 4A
I.D. FAN 3A
FLY ASH PUMP HOUSE
I.D. FAN 3B
FLY ASH PU HO
OPERATING FLOOR PLAN

Figure 4-2. ESP layout for Labadie plant.

TABLE 4-12. SUMMARY OF DSD/FSI RETROFIT RESULTS FOR LABADIE PLANT
(March 1988 Dollars)

Boilers	After Site Visit		Before Site Visit
	1-3	4	1-4
Site Access/Congestion			
Reagent preparation	Low	Low	Medium
ESP Upgrade	High	Medium	Low
New baghouse	NA	NA	NA
Scope Adders			
Change ESP ash discharge system to dry handling	Yes	Yes	No
Estimated cost (1,000$)	4,714	4,714	NA
Additional duct work (feet)			
New baghouse case	NA	NA	NA
Estimated cost (1,000$)	NA	NA	NA
ESP reuse case	NA	NA	NA
Estimate cost (1,000$)	NA	NA	NA
Duct demolition length (feet)	50	50	50
Demolition cost (1,000$)	118	118	118
Total cost (1,000$)			
ESP upgrade case	4,832	4,832	118
New baghouse case	NA	NA	NA
Retrofit Factors			
Control system (DSD system only)	1.13	1.13	1.25
ESP upgrade	1.59	1.38	1.13
New baghouse	NA	NA	NA

TABLE 4-13. RETROFIT FACTORS AND COSTS FOR DSD/FSI USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor (ESP/FF)	Scope Cost ($1,000)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
DSD + Reused ESP	1	59.0	1.59	4,832	54.7	714.4	24.1	7.5	49	33,714
	2	52.2	1.59	4,832	54.7	760.5	22.6	8.0	49	29,714
	3	57.9	1.59	4,832	54.7	720.3	23.9	7.6	49	33,143
	4	58.5	1.38	4,832	53.6	709.2	23.9	7.5	49	33,714
FSI + ESP	1	59.0	1.59	4,832	47.4	848.5	29.4	9.2	50	34,650
	2	52.2	1.59	4,832	47.4	880.4	26.9	9.5	50	30,539
	3	57.9	1.59	4,832	47.4	852.6	29.0	9.2	50	34,062
	4	58.5	1.38	4,832	46.0	842.0	29.2	9.1	50	34,650

Application of DSD at the four Labadie boilers would reduce plant level SO_2 emissions by approximately 127,618 tons per year, assuming a 48 percent level of control. The cost per ton of SO_2 removed ranges from $465 to $501.

Application of FSI at these units would reduce SO_2 emissions by 132,935 tons per year, assuming a 50 percent level of control. The cost per ton of SO_2 removed ranges from $756 to $787.

SECTION 5

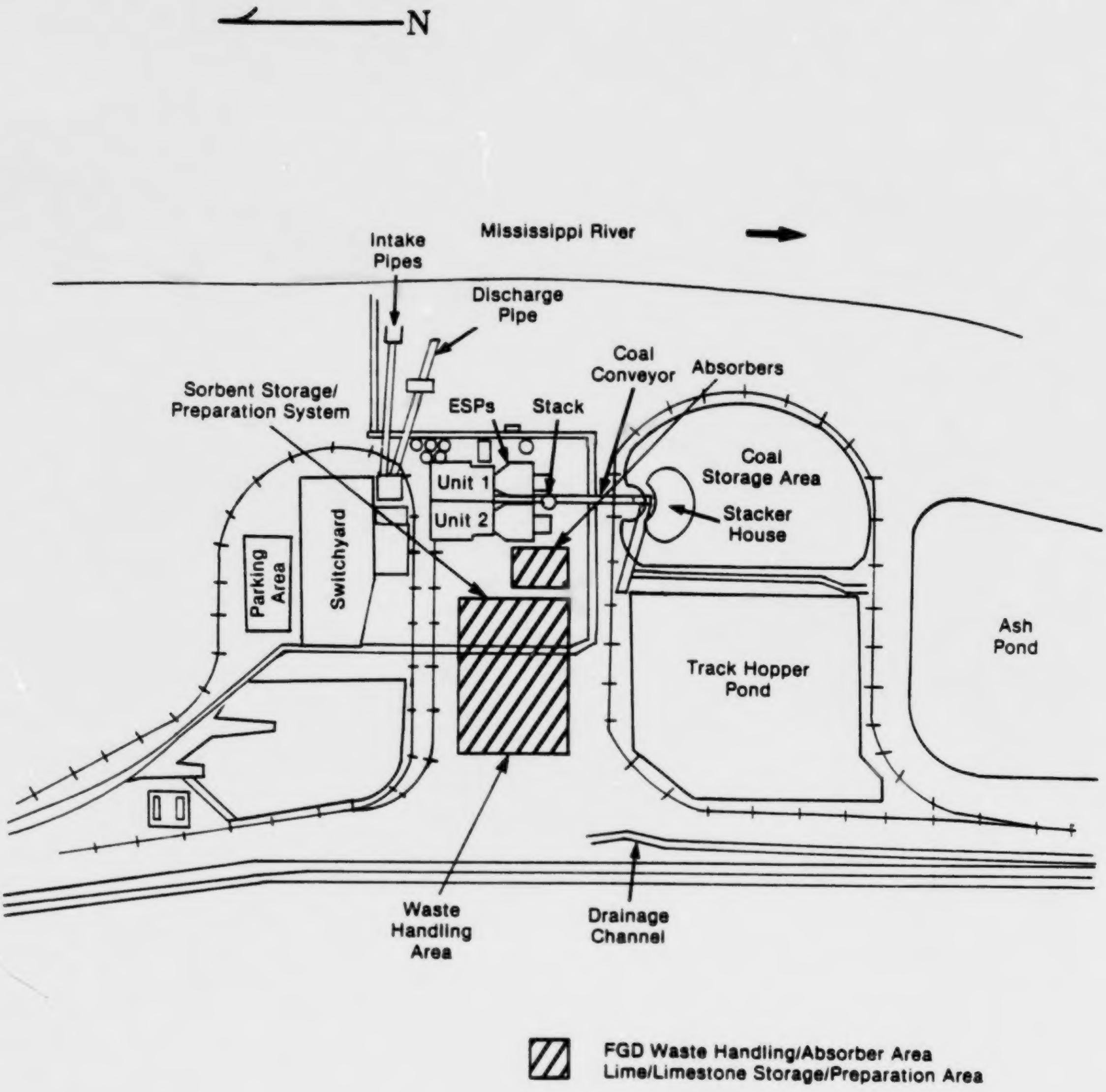
RUSH ISLAND STEAM PLANT

The Rush Island steam plant is located within Jefferson County, Missouri, and is a part of the Union Electric Company system. The plant is bounded by the Mississippi River to the east and by rolling hills to the west. The plant contains two coal-fired boilers with a gross generating capacity of 1,241 MW. Figure 5-1 shows the location of the two boilers and other plant auxiliary equipment. Table 5-1 presents operational data for the existing equipment at the Rush Island steam plant.

Both boilers burn a 1.2 percent sulfur Illinois coal from the Consolidation Coal Company's Burning Star Mine No. 5. Coal shipments are received by railroad and are conveyed to a coal storage and handling area south of the boilers. The low-sulfur coal allows the Rush Island plant to comply with the state implementation plan for sulfur dioxide emissions.

Each unit has a Combustion Engineering subcritical, pulverized coal boiler with a furnace volume of 517,000 cubic feet and 1,005°F superheater outlet. Each boiler has twenty-four tangential burners--six burners are in each corner. Capacity factors used to analyze the cost of individual technologies for units 1 and 2 are 42.4 and 58.9 percent, respectively. Current plant emission rates for SO_2 and NO_x are 2.2 and 0.7 lb per million BTU, respectively.

Particulate matter emissions are controlled with ESPs located behind each boiler unit. Fly ash from both units is wet sluiced to ponds southwest of the coal pile. Both boilers are served by a common chimney located between the boilers and coal storage area. The chimney is 700 feet in height and is constructed of reinforced concrete with a corten steel liner.


N
Mississippi River
Intake Pipes
Discharge Pipe
Coal Conveyor
Absorbers
Sorbent Storage/ Preparation System
ESPs
Stack
Coal Storage Area
Unit 1
Unit 2
Stacker House
Parking Area
Switchyard
Ash Pond
Track Hopper Pond
Waste Handling Area
Drainage Channel
▨ FGD Waste Handling/Absorber Area
Lime/Limestone Storage/Preparation Area

Not to scale

Figure 5-1. Rush Island Plant plot plan.

TABLE 5-1. RUSH ISLAND STEAM PLANT OPERATIONAL DATA

Item[a]	Units 1-2
Boiler and Stack Data	
Gross generating capacity (MW)	620.5
Boiler manufacturer	Combustion Engineering
Installation data	1976 & 1977
Capacity factor (percent)	42.4 & 58.9
Boiler type/firing type	Tangential
Boiler bottom type	Dry
Boiler dimensions (D x W x H, ft.)[b]	51.8 x 60.8 x 109.3
Burner type	Tangential
Total number of burners	24
Number of burner rows	6
Number of burners per row	4
Nose/top burner row (ft.)	62.3
Excess air (percent)	23
Flue gas flow rate (10^3 cfm)	1330
Slagging/fouling	No
Operating mode (Baseloaded, Intermediate, Peaking)	Baseloaded
Stack number	1
Fuel Data	
Coal quality	
Heat content (BTU/lb)	10,577
Volatile matter (percent)	31.0
Ash (percent)	8.2
Moisture (percent)	12.16
Sulfur (percent)	1.2
Fixed carbon (percent)	48.6
Coal delivery method	Railroad

(Continued)

TABLE 5-1. (CONTINUED)

Item[a]	Units 1-2
Particulate Control Equipment Data	
Type of control	ESP
Installation date	1976 & 1977
Emissions (lb/MMBTU)	0.006
Emission standard (lb/MM BTU)	0.12
Removal efficiency	99.4
Design specification	
Sulfur specification (percent)	1.0
Surface area (1000 ft^2)	933.1
Gas exit rate (1000 ACFM)	3340
SCA (ft^2/1000 ACFM)	279
Outlet temperature (^{o}F)	270
Fly ash disposal method	Wet/On-site

[a] Based on 1987 data.

[b] Furnace height from top of ash hopper to furnace nose.

5.1 L/LS-FGD RETROFIT DIFFICULTY FACTORS AND COSTS

5.1.1 Lime/Limestone FGD and Lime Spray Drying FGD Layouts

Figure 5-1 shows the general layout and location of the FGD control system. Two FGD absorber layouts were considered: 1) between the unit ESPs and the coal storage area and 2) west of the unit 2 ESPs. No major demolition or relocation is necessary with either layout. The first layout leaves space for the construction of other units but results in moderate access/congestion. However, current plans to build future units have been dropped, and using the open space adjacent to unit 2 reduces the FGD access/congestion factors and the distance to the sorbent preparation and waste handling areas. The first layout was evaluated using the simplified procedures before the site visit. The second layout was evaluated using the simplified procedures after the site visit. Table 5-2 presents the L/LS-FGD and LSD-FGD cases considered and the anticipated SO_2 removal.

5.1.2 Retrofit Difficulty and Scope Adder Costs

In this section detailed retrofit FGD cost estimating procedures have been used to develop retrofit factors for the Rush Island plant. Two site locations are possible for the placement of the unit 1 and 2 absorbers. One location is between the coal pile and units 1 and 2, on either side of the coal conveyor, close to the common chimney. The second location is to the west of unit 2 ESPs. The first location initially was considered for absorber placement, since it was thought that possible future units would be constructed to the west of unit 2. However, plant personnel indicated that no additional units would be added to the plant. As such, the second location to the west of the plant is also evaluated for absorber placement in this study, due to the large available space. Space between the units and the coal handling area is limited, which would result in a moderately high site access/congestion factor. By contrast, to the west of unit 2 is an open area with no obstructions. Low site access/congestion factors have been assigned to this location.

Table 5-2. SUMMARY OF L/LS-FGD AND LSD-FGD CASES EVALUATED FOR RUSH ISLAND PLANT

Case Description	SO_2 Removal (percent)	Coal Sulfur (wt. percent)	Capacity Factor (percent)	SO_2 Reduction (tons per year)
L/LS-FGD				
Boiler 1	90	1.2	42.4	22,935
Boiler 2	90	1.2	58.9	32,218
LSD-FGD				
Boiler 1	70	1.2	42.4	19,443
Boiler 2	70	1.2	58.9	27,313

For the flue gas handling system, a moderate site access/congestion factor is assigned to the first location and a low site access/congestion factor is assigned to the second. For both locations, medium underground obstruction factors are assigned to the flue gas handling, since some underground obstructions exist close to the ESPs and chimney. Duct runs of 150/780 and 150/500 feet are required for units 1 and 2, respectively, for each location.

LSD with reused ESP is the only LSD-FGD technology considered for both units, since both boilers have moderate size ESPs (SCA >270). LSD absorbers can be placed in similar locations, as in the case of L/LS-FGD, with the same site access/congestion and underground obstruction factors being assigned. For the unit 1 flue gas handling, medium site access/congestion and underground obstruction factors are assigned. These factors represent access difficulty to the upstream of the unit 1 ESPs and congestion created by the unit 1 ESPs. If absorbers for unit 1 are located to the west of unit 2, in order to access the unit 1 ESPs, duct runs must pass over the unit 2 ESPs, creating congestion and access difficulties. Therefore, LSD absorbers for unit 1 are located behind the ESP boxes; the second option (west of unit 2) is not considered in this sutdy. For unit 2, it is easier to access the ESPs from the side of unit 2 (west). For unit 2, medium site access/congestion and underground factors are assigned to flue gas handling. Flue gas from the boiler is divided into two duct runs prior to the ESPs. It is relatively easy to access the outer duct run upstream of the unit 2 ESPs. By contrast, access to the inner duct run is difficult. Therefore, a median of the two access difficulties is used in this study and a medium site access/congestion factor is assigned to the unit 2 flue gas handling system for LSD-FGD. Duct runs of 700 and 560 feet are required for units 1 and 2, respectively. No costs are included for an extended outage, if required, to tie-in to the existing ductwork between the airheater and ESPs. However, costs do include additional fan capacity needed to overcome the pressure drop due to the additional ductwork and absorbers.

If additional ESP plate area is required, the additional plate area would likely be tied-in after the existing induced draft fans (located on either side of the common chimney) in the space between the units and the coal storage area. A medium site access/congestion factor is assigned to these locations because of the interference caused by the coal conveyor.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Table 5-3. The largest scope adders for both boilers are for the conversion of the fly ash conveying system from wet to dry. It was assumed that the fly ash would be necessary to stabilize the scrubber sludge waste resulting from conventional L/LS-FGD application and to prevent plugging of the sluice lines in the LSD-FGD system for the ESP reuse case.

The retrofit factors determined for the L/LS-FGD cases range from 1.31 for unit 2 to 1.39 for unit 1 with absorber location to the west of unit 2. The retrofit factor is 1.39 for both units if the absorbers are located behind the chimney. Similar retrofit factors, consequently, exist for both absorber locations, since site access/congestion and duct length factors offset each other. The retrofit factors for LSD-FGD cases range from 1.36 for unit 2 to 1.53 for unit 1. Table 5-4 and 5-5 summarize the retrofit factor data for the L/LS-FGD and LSD-FGD technologies. For L/LS-FGD technology the absorber location to the west of unit 2 was selected for this study.

5.1.3 Simplified Versus Detailed Retrofit Factor Procedure Results

The previous section presents the results of detailed procedures analysis based on a site visit to the Rush Island plant. In this section, the simplified procedure results made before the site visit and reused after the site visit are compared with the detailed procedure results.

Prior to the site visit, retrofit factors were developed using the simplified procedures based on available information such as plot plan and EIA-767 form. After the site visit, input variables to the simplified procedures were examined (i.e., site access/congestion, scope adders) for accuracy. As mentioned in the previous sections, prior to the site visit to Rush Island plant, absorbers were located between the units and coal pile on either side of the coal conveyor. This location was chosen, rather than west of unit 2, so that sufficient space would remain available beside unit 2 for future unit construction. The space between each unit and the coal pile is

TABLE 5-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR RUSH ISLAND PLANT

Scope Adjustment	Description[a]
• Chimney liner	Chimney liner for L/LS-FGD cases for both boilers ($4.49/kW).
• Modify draft controls	Boiler draft control modifications/ upgrades were required due to increased pressure drop and added fan capacity ($1.42 kW).
• Wet to dry ash handling system	Fly ash handling system is changed from wet to dry for both units for sludge stabilization in the case of L/LS-FGD and to prevent plugging of the sluice lines in the case of LSD-FGD ($7.76/KW).

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[a] Costs shown are based on 1987 dollars and have been adjusted for location, process, retrofit, and other considerations.

TABLE 5-4. SUMMARY OF RETROFIT FACTOR DATA FOR L/LS-FGD AT RUSH ISLAND PLANT USING DETAILED PROCEDURES

Item	Boilers 1	2
Site Access/Congestion		
Reagent feed	Low	Low
SO_2 removal	Low	Low
Flue gas handling	Low	Low
Waste handling	Base	Base
General support equipment	Low	Low
ESP Upgrade	NA	NA
Underground Obstruction		
Reagent feed	Low	Low
SO_2 removal	Low	Low
Flue gas handling	Medium	Medium
Waste handling	Base	Base
General support equipment	Low	Low
ESP Upgrade	NA	NA
Total Inlet and Outlet Ductwork (ft.)	780	500
Scope Adders		
New chimney	No	No
Chimney liner	Yes	Yes
Modify Draft controls	Yes	Yes
Wet to Dry Ash Handling Systems	Yes	Yes
Retrofit Factors		
FGD System	1.39	1.31
ESP Upgrade	NA	NA
General Facilities (percent)	5	5
Engineering and Home Office Fees (percent)	11	11

NA = Not applicable.

TABLE 5-5. SUMMARY OF RETROFIT FACTOR DATA FOR LSD-FGD AT RUSH ISLAND PLANT USING DETAILED PROCEDURES

Item	Boilers 1	Boilers 2
Site Access/Congestion		
Reagent feed	Low	Low
SO_2 removal	Medium	Low
Flue gas handling	Medium	Medium
Waste handling	NA	NA
General support equipment	Low	Low
ESP Upgrade	Medium	Medium
Underground Obstruction		
Reagent feed	Low	Low
SO_2 removal	Low	Low
Flue gas handling	Medium	Medium
Waste handling	NA	NA
General support equipment	Low	Low
ESP Upgrade	High	High
Total Inlet and Outlet Ductwork (ft.)	700	560
Scope Adders		
New chimney	No	No
Chimney line	No	No
Modify draft controls	Yes	Yes
Wet to dry handling system	Yes	Yes
Retrofit Factors		
FGD System	1.53	1.36
ESP Upgrade	1.38	1.38
General Facilities (percent)	5	5
Engineering and Home Office Fees (percent)	11	11

NA = Not applicable.

congested by the ESPs and the chimney to the north, the coal pile to the south, and the coal conveyor located midway between the units. As a result, a high site access/congestion factor was assumed for this location. Retrofit factors of 1.51 for L/LS-FGD and 1.69 for LSD-FGD were estimated for these units. After the site visit, since plant personnel indicated that no future units would be constructed at Rush Island Plant, the area to the west of unit 2 are evaluated for absorber placement. This area has low site access/ congestion but requires longer duct runs. If the absorbers are located behind the ESPs, a moderate site access/congestion factor, rather than high (as used in prior to the site visit), is assigned. Locating the absorbers to the west of unit 2 decreases the overall retrofit factors by 5 to 9 percent for L/LS-FGD cases. Tables 5-6 and 5-7 present the retrofit factors using the simplified procedure methodology.

Table 5-8 presents the retrofit factors developed using the simplified procedure methodology prior to and after the site visit and results obtained using the detailed procedure. The absolute percent differences between the simplified and detailed procedures after the site visit range from 4 to 5 percent for L/LS-FGD and 1 to 5 percent for LSD-FGD. These differences are due to less inputs to the simplified procedure as compared to the detailed procedure (specifically for the flue gas handling system). Using the simplified procedures duct length is selected as a range. For the detailed procedures, a specific duct length input, rather than a range, is required.

As Table 5-8 shows, the percent difference between the simplified procedures prior to the site visit and detailed procedures after the site visit for L/LS-FGD are -9 to -15 percent for units 1 and 2, respectively, compared to -4 and -5 percent for simplified and detailed procedures after the site visit. For location of the absorbers behind the chimney, the arrangements are the same as for the assigned location prior to the site visit. However, the site access/congestion factor was corrected from high to medium. Therefore, retrofit factors are lower than estimated before the site visit. In locating the absorbers to the west of the plant, arrangements are different, which results in lower retrofit factors due to the low site access/congestion.

TABLE 5-6. SUMMARY OF RETROFIT FACTOR DATA FOR RUSH ISLAND UNIT 1 USING SIMPLIFIED PROCEDURES (AFTER THE SITE VISIT)

Item	FGD Technology L/LS-FGD	 LSD-FGD
Site Access/Congestion		
SO_2 removal	Low	Low
Flue gas handling	Low	
ESP Reuse Case		Medium
Baghouse Case		NA
Duct work Distance (ft.)	600-1000	
ESP Reuse		600-1000
Baghouse		NA
ESP Reuse	NA	Medium
New Baghouse	NA	NA
Scope Adjustments		
Wet to dry	Yes	Yes
Estimated Cost (1000$)	4823	4823
New Chimney	No	No
Estimated cost (1000$)	0	0
Other	No	No
Retrofit Factors		
FGD System	1.44	
ESP Reuse case		1.45
Baghouse case		NA
ESP upgrade	NA	1.38
New baghouse	NA	NA
General Facilities (percent)	5	5

NA = Not applicable.

TABLE 5-7. SUMMARY OF RETROFIT FACTOR DATA FOR RUSH ISLAND UNIT 2 USING SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

Item	FGD Technology	
	L/LS-FGD	LSD-FGD
Site Access/Congestion		
SO_2 removal	Low	Low
Flue gas handling	Low	
ESP Reuse Case		Medium
Baghouse Case		NA
Duct work Distance (ft.)	300-600	
ESP Reuse		300-600
Baghouse		NA
ESP Reuse	NA	Medium
New Baghouse	NA	NA
Scope Adjustments		
Wet to dry	Yes	Yes
Estimated Cost (1000$)	4823	4823
New Chimney	No	No
Estimated cost (1000$)	0	0
Other	No	No
Retrofit Factors		
FGD System	1.38	
ESP Reuse case		1.38
Baghouse case		NA
ESP upgrade	NA	1.38
New baghouse	NA	NA
General Facilities (percent)	5	5

NA = Not applicable.

TABLE 5-8. RETROFIT FACTOR COMPARISONS BETWEEN THE SIMPLIFIED AND DETAILED PROCEDURES

FGD CASES	Simplified Procedure (Prior to site visit)	Simplified Procedure (After site visit)	Detailed Procedure	Percent Difference[a]	
				Before[b]	After[c]
L/LS-FGD					
Unit 1	1.51[c]	1.44[d]	1.39	-9	-4
Unit 2	1.51[c]	1.38[d]	1.31	-15	-5
LSD-FGD					
Unit 1	1.69[c]	1.45[c]	1.53	-10	5
Unit 2	1.69[c]	1.38[c]	1.36	-24	-1

[a] [(Detailed Procedure - Simplified Procedure)/Detailed Procedure] * 100.

[b] Before site visit.

[c] After site visit.

For LSD-FGD, the unit 1 absorber was placed behind the ESP boxes and a medium site access/congestion factors was assigned to this location rather than high (as was used prior to the site visit). For unit 2, a location to the west of unit 2 was used for absorber placement with a low retrofit factor being assigned to this location. Therefore, the estimated retrofit factor was lower than the estimated value prior to the site visit.

5.1.4 Summary of FGD Retrofit Costs

Table 5-9 presents the process area retrofit factors and indirect costs (as percentages) and costs for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1 and 2.

Application of L/LS-FGD would reduce the plant level SO_2 emissions by approximately 55,410 tons per year assuming a 90 percent level of control. The cost per ton of SO_2 ranges from $1,353 to $1,778.

Application of LSD-FGD at all units would reduce the plant level SO_2 emissions by approximately 46,970 tons per year assuming a 76 percent level of control. The cost per ton of SO_2 removed ranges from $1,120 to $1,630.

5.2 COAL SWITCHING AND PHYSICAL COAL CLEANING

To estimate the cost of coal switching, the simplified procedures used one of the IAPCS base coals as the switch coal. For the Rush Island plant, this coal was a West Virginia/Eastern Kentucky low sulfur bituminous coal. The IAPCS model assumes that the switch coal costs 5 and 15 dollars per ton more than the current coal. Additionally, costs for ESP upgrading using SO_3 conditioning and changes in waste disposal costs due to increases/decreases in ash disposal are included. The following data compares the properties of the coal currently fired at Rush Island versus the IAPCS low sulfur bituminous coal.

Coal Parameter	Rush Island	IAPCS Coal
HHV - BTU per pound	10,513	12,058
Sulfur - percent	1.1	0.9
Ash - percent	8.2	16.6

TABLE 5-9. RETROFIT FACTORS AND COSTS FOR L/LS-FGD AND LSD-FGD USING THE IAPCS MODEL

(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	FGD Retrofit Factor	Particulate Control Retrofit Factor	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
L/LS-FGD	1	42.4	1.39	--	47.4	209.1	2,483.1	56.9	24.9	90	22,935
+ Additive	2	58.9	1.31	--	47.4	198.9	1,873.0	60.3	18.8	90	32,218
LSD-FGD	1	42.4	1.53	1.38	50.3	120.2	1,542	30.0	13.1	76	19,443
+ Reuse ESP	2	58.9	1.36	1.38	50.3	108.3	1,103	30.1	9.4	76	27,313

The Rush Island plant does not have adequate facilities to blend different coals because it currently receives a single Illinois bituminous coal. The plant receives coal by unit train, and coal for both units is stored and reclaimed from a single storage pile. However, there would be no major additional capital costs for switching to a lower sulfur bituminous coal as long as blending was not desired. Use of a lower sulfur coal is not likely to require significant ESP upgrading. The Rush Island plant has an emission limit of 0.12 lb per million BTU, and current emission levels are low (0.006). The IAPCS estimates include costs for ESP upgrade.

The Rush Island boilers do not have slagging problems when operating at full load and small amounts of western subbituminous coals have been successfully fired on these boilers. However, as is the case with other boilers designed to fire bituminous coals, significant unit derating would occur if much subbituminous coal was burned.

Physical coal cleaning was evaluated using the IAPCS coal database option. Using this option, IAPCS searches the database for a coal similar to the current coal using the following coal parameters: sulfur content, rank, and region. The level of coal cleaning is provided, and the model uses the cost of cleaning the database coal to the cleaning level specified. No information was provided by the plant during the visit to better determine the coal cleaning characteristics of the coals currently used. Because this Illinois coal is probably already being cleaned to some degree, only a 30 percent SO_2 removal through additional coal cleaning was estimated by IAPCS.

5.3 SELECTIVE CATALYTIC REDUCTION

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for SCR were reviewed for accuracy. The most important parameters which will impact the cost of retrofitting SCR are:

- reactor access and congestion,
- flue gas duct length to and from the reactor, and
- demolition costs of existing equipment and general facilities percentage.

These parameters are impacted by the location chosen for the SCR reactor. The SCR system type (tail-end) and the reactor location chosen before and after the site visit are the same. Table 5-10 presents the retrofit factors and scope adder costs estimated for the Rush Island plant before and after the site visit. The SCR reactors for units 1 and 2 are located directly behind (south) their respective ESPs north of the coal pile either sides of the coal conveyor. Both reactors are assumed to be in areas with high underground obstructions. The ammonia storage system is placed to the west of unit 2 in a remote area having a low access/congestion factor. The site access/congestion factor and scope adders for both units were not changed.

The NO_x control technologies are evaluated independently from SO_2 technologies. However, if both SO_2 and NO_x emissions need to be reduced at Rush Island plant, the SCR reactors would have to be located immediately downstream of the FGD absorbers. This would result in a moderate-to-high access/congestion factor if the FGD absorbers are located the units and a low access/congestion factor if the absorbers are located to the wet of unit 2.

Table 5-11 presents the estimated cost of retrofitting SCR at the Rush Island boilers. Application of SCR would reduce NO_x emissions by 15,785 tons per year if 80 percent reduction is achieved; the cost per ton of NO_x removed ranges from $6,564 to $9,032.

5.4 SORBENT INJECTION AND REPOWERING

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most important parameters which will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance and difficulty of upgrade (access/congestion associated with adding plate area),
- need for converting wet ash handling system to a dry system, and

TABLE 5-10. SUMMARY OF SCR RETROFIT RESULTS FOR RUSH ISLAND PLANT

Item	Boiler 1	Boiler 2
Site Retrofit Results		
Site access and congestion		
for SCR reactor	Low	Low
for flue gas handling	Low	Low
Scope Adder Parameters		
Building demolition (1,000$)	0	0
Ductwork demolition (1,000$)	106	106
New duct length (feet)	160	160
New duct costs (1,000$)	2,317	2,317
New heat exchanger (1,000$)	5,581	5,581
Total Scope Adder Costs (1,000$)	8,004	8,004
Retrofit Factor for SCR	1.16	1.16
General Facilities (percent)	13	13

TABLE 5-11. RETROFIT FACTORS AND COSTS FOR SCR USING THE IAPCS MODEL

(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor	Scope Cost ($1,000)	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent NO_x Removed	Tons/year NO_x Reduced
SCR	1	42.4	1.16	8,004	88.0	117.1	4,162.5	27.2	11.9	80	6,534
3 yr catalyst life	2	58.9	1.16	8,004	88.0	117.2	3028.5	27.8	8.7	80	9,179

- sufficient flue gas residence time between the air heater and particulate control device to allow for DSD droplet drying (2 seconds of straight duct run) or humidification with FSI.

Based on the EIA-767 form, it was known prior to the site visit that the ESPs had an SCA of 279 and had good removal efficiencies relative to the emission limit of .12 lb/MMBTU. Additionally, it was assumed that the fly ash was disposed of dry and that sufficient duct residence time was available between the air heater and ESP to allow for adequate DSD droplet drying or, if not, that the ESP was large enough to apply the E-SO_x technology. The E-SO_x technology uses advanced particulate control concepts to enhance the performance of an existing ESP such that the first ESP section can be converted to a spray injection section. This technology is under field pilot scale development at this time.

Based on the site visit, it was learned that each unit at Rush Island has six ESP boxes in parallel. Figure 5-2 presents the plot plan for the Rush Island boiler ESP boxes and flue gas ducting. The flue gas from each unit is split in half and passes in parallel through one of three ESP boxes. As such, the duct residence time to the third box is quite long and the flue gas residence time to the first box is short. However, all ESP boxes should be good candidates for the E-SO_x technology because of the reduced flue gas flow rate and overall good particulate removal performance currently being achieved. Sufficient duct residence time does appear to exist in front of all boxes to allow for humidification when applying FSI.

It was assumed prior to the site visit that the access/congestion factor for particulate control upgrading was medium. Although the side-by-side layout of the units restricts plate area addition to the existing boxes adjacent to the other unit, there is sufficient space immediately behind the third ESP boxes for addition. Because the actual SCA of the ESPs is 279, it is not likely that additional plate area would be needed for the sorbent injection technologies due to the good removal efficiences currently being achieved.

It was determined by the site visit that the plant uses a wet ash disposal system which would have to be converted to a dry system if any of the sorbent injection technologies were applied at Rush Island. Although the

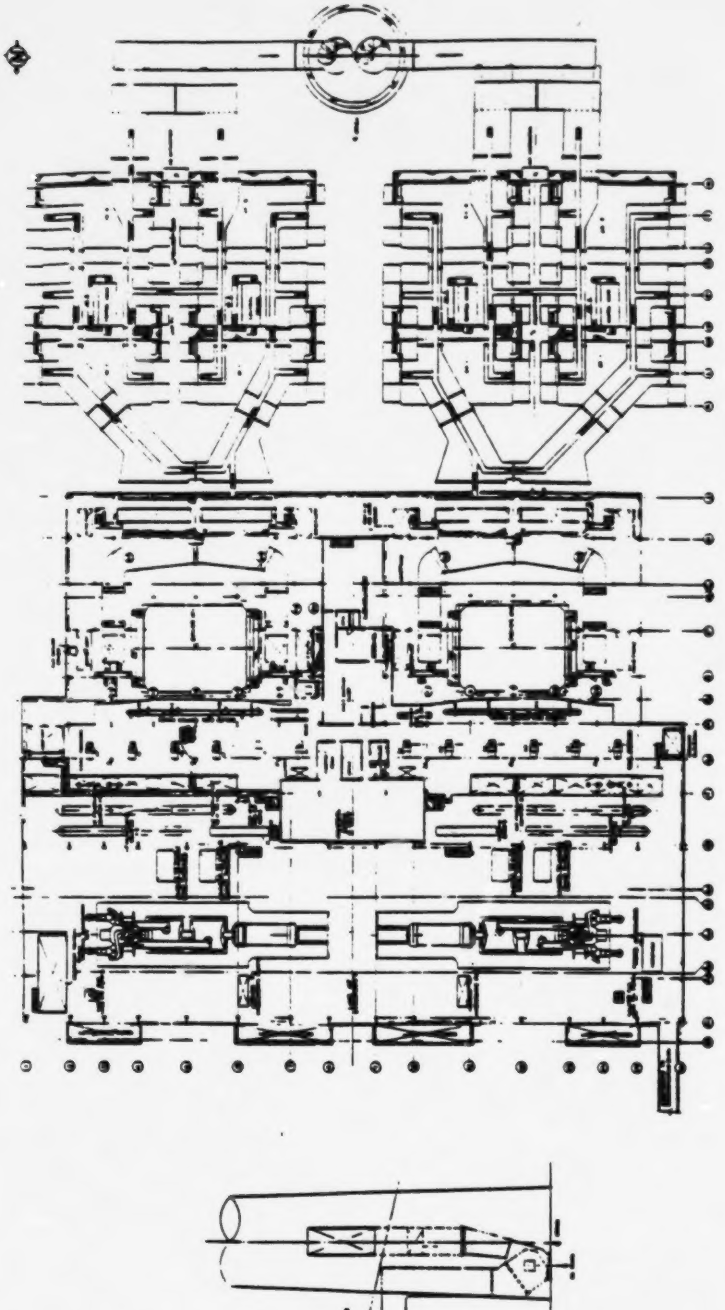
OPERATING FLOOR PLAN

Figure 5-2. ESP layout for the Rush Island plant.

EIA-767 form indicates that the fly ash is disposed of wet, a misunderstanding in communication with the company personnel resulted in assuming that the plant had a dry ash handling system when conducting the evaluation before the site visit.

Table 5-12 presents the before and after site visit estimates for the retrofit difficulty factors and scope adders for the Rush Island units. No major changes were made for this plant. Table 5-13 presents the costs estimated to retrofit DSD and FSI at the Rush Island plant.

Application of DSD at all units would reduce plant level SO_2 emissions by approximately 29,553 tons per year assuming a 48 percent level of control. The cost per ton of SO_2 ranges from $680 to $856.

Application of FSI at the Rush Island units would reduce plant level SO_2 emissions by approximately 30,784 tons per year assuming a 48 percent level of control; the cost per ton of SO_2 removed ranges from $951 to $1,112.

TABLE 5-12. SUMMARY OF DSD/FSI RETROFIT RESULTS FOR RUSH ISLAND PLANT

Item	
Site Access/Congestion	
Reagent preparation	Low
ESP Upgrade	Low - Medium
New baghouse	NA
Scope Adders	
Change ESP ash discharge system to dry handling	Yes
Estimated cost (1,000$)	4823
Additional duct work (ft.)	
New baghouse case	NA
Estimated cost (1,000$)	NA
ESP reuse case	NA
Estimate cost (1,000$)	NA
Duct demolition length (ft.)	50
Demolition cost (1,000$)	118
Total cost (1,000$)	
ESP upgrade case	4941
New baghouse case	NA
Retrofit Factors	
Control system (DSD system only)	1.13
ESP upgrade	1.38
New baghouse	NA

NA = Not applicable.

TABLE 5-13. RETROFIT FACTORS AND COSTS FOR DSD/FSI USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor (ESP/FF)	Scope Cost ($1,000)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
DSD + Reused ESP	1	42.4	1.38	4,941	40.4	1,153.6	14.3	6.3	49	12,397
	2	58.9	1.38	4,941	40.4	942.5	16.4	5.1	49	17,415
LIMB + ESP	1	42.4	1.38	4,941	46.0	1,272.2	16.2	7.1	50	12,741
	2	58.9	1.38	4,941	46.0	1,086.3	19.4	6.1	50	17,899

SECTION 6

MERAMEC STEAM PLANT

The Meramec steam plant is located along the Mississippi River within St. Louis County, Missouri, as part of the Union Electric Company system. The plant contains two tangential and two front-wall coal-fired boilers with a total gross generating capacity of 923 MW. Figure 6-1 shows the location of all boilers and plant auxiliary equipment. Table 6-1 presents operational data for the existing equipment at the Meramec steam plant.

All boilers burn low-sulfur Illinois coal (1.1 percent). Coal shipments are received by barge (railroad coal delivery is also available, but this portion of the coal handling system will require restoration) and are conveyed to a coal storage and handling area south of the plant. Low-sulfur coal allows the Meramec plant to comply with the state implementation plan for sulfur dioxide emissions.

Units 1 and 2 have Combustion Engineering and Units 3 and 4 have Foster Wheeler pulverized coal boilers. Units 1 and 2 are Tangential and units 3 and 4 are front wall coal-fired boilers.

Capacity factors used to analyze the cost of individual technologies for units 1 through 4 are 10.1, 12.8, 11.3, and 11.6 percent, respectively. Since the Meramec plant is older and more expensive to maintain and operate than the other three Union Electric coal-burning plants considered in this study, the capacity factors are typically low (about 10 percent). Current plant emission rates for SO_2 are 2.1 lb per million BTU for all units. Emission rates for particulate matter are 0.6 and 0.9 lb per million BTU.

Particulate matter emissions are controlled with ESPs located behind each boiler unit. Retrofit ESPs are added behind the chimneys/existing ESPs. Fly ash from all units is wet sluiced to several large on-site ponds located west and north of the plant. Each unit is served by its own chimney located between the ESPs.

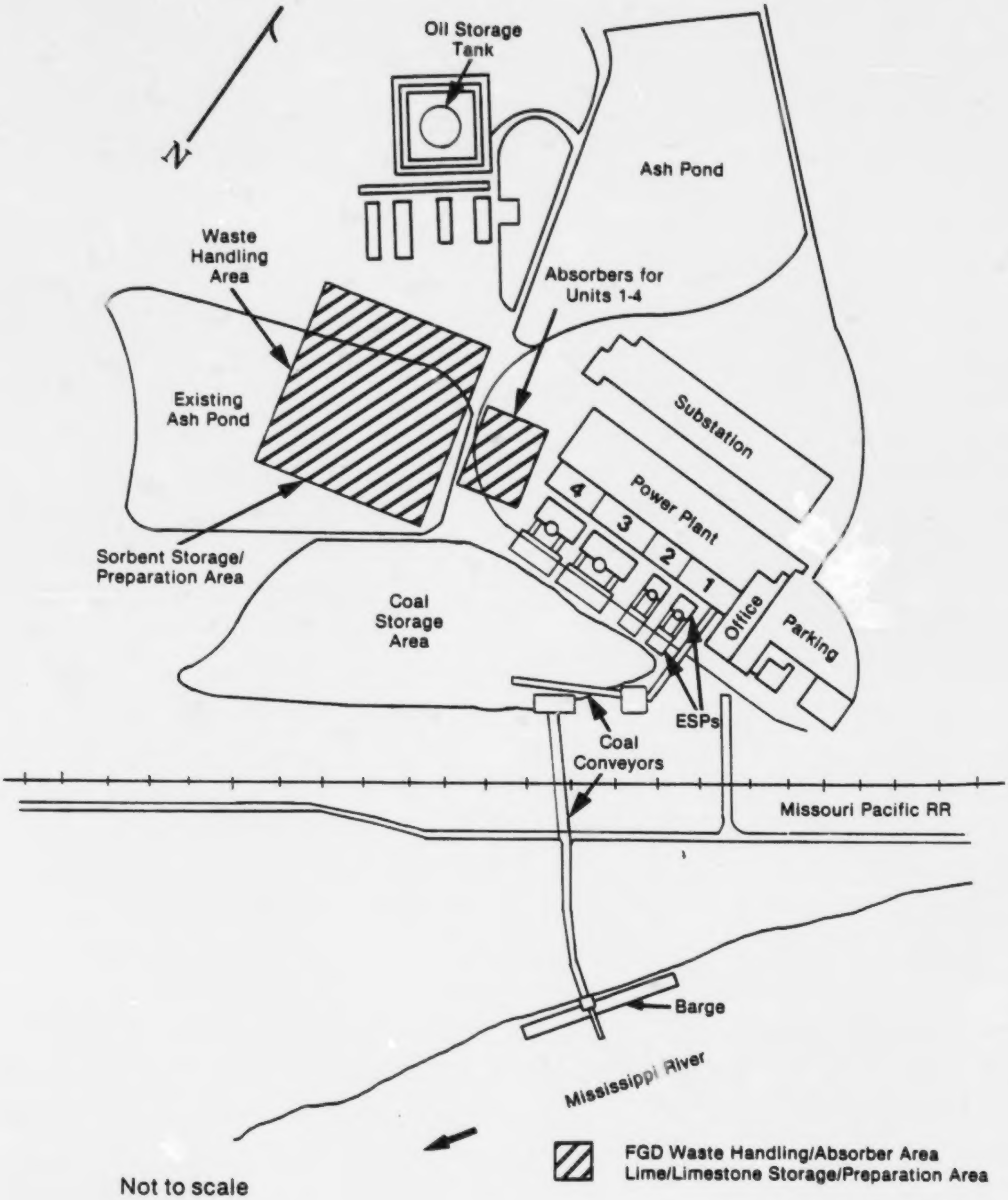
N
Oil Storage Tank
Ash Pond
Waste Handling Area
Absorbers for Units 1-4
Existing Ash Pond
Substation
Power Plant
4
3
2
1
Office
Parking
Sorbent Storage/ Preparation Area
Coal Storage Area
ESPs
Coal Conveyors
Missouri Pacific RR
Barge
Mississippi River
▨ FGD Waste Handling/Absorber Area
Lime/Limestone Storage/Preparation Area
Not to scale

Figure 6-1. Meramec Plant plot plan.

TABLE 6-1. MERAMEC STEAM PLANT OPERATIONAL DATA

Item[a]	Units 1-2	Unit 3	Unit 4
Boiler and Stack Data			
Gross generating capacity (MW)550	137.5	289	350
Boiler manufacturer	Combustion Engineering	Foster Wheeler	Foster Wheeler
Installation data	1953 - 1954	1959	1961
Capacity factor (percent)	10.1 - 12.8	11.3	11.6
Boiler type/firing type	Tangential	Front wall	Front wall
Boiler bottom type	Dry	Dry	Dry
Burner type	Tangential	Intervane	--
Total number of burners	16	12	--
Number of burner rows	4	4	--
Number of burners per row	4	4	--
Nose/top burner row (ft.)	43	--	--
Burner spacing (vert. x horiz. ft.)	3.7	--	--
Excess air (percent)	23	23	23
Flue gas flow rate (10^3 cfm)	230	471	574
Slagging/fouling	None	None	None
Operating mode (i.e., base, Intermediate, etc.)	Cycling	Cycling	Cycling
Fuel Data			
Coal quality			
Heat content (BTU/lb)	12,004	12,004	12,004
Volatile matter (percent)	31.5	31.5	31.5
Ash (percent)	6.6	6.6	6.6
Moisture (percent)	12.2	12.2	12.2
Sulfur (percent)	1.3	1.3	1.3
Fixed carbon (percent)	49.8	49.8	49.8
Coal delivery method	Barge	Barge	Barge

(Continued)

TABLE 6-1. (CONTINUED)

Item[a]	Units 1-2	Unit 3	Unit 4
Particulate Control Equipment Data			
Type of control	ESP	ESP	ESP
Installation date (ESP Upgrade)	1981	1982	1981
Emissions (lb/MMBTU)	0.001	0.004	0.0006
Emission standard (lb/MMBTU)	0.12	0.12	0.12
Removal efficiency	99.6	99.5	99.8
Design specification			
Sulfur specification (percent)	0.9	0.9	0.9
Surface area ($1000\ ft^2$)	295.6	608.4	790.5
Gas exit rate (1000 ACFM)	600	1,165	1,450
SCA (ft^2/1000 ACFM)	492	522	545
Outlet temperature (°F)	330	360	365
Fly ash disposal method	Wet sluiced/ on-site	Wet-sluiced/ on-site	Wet sluiced/ on-site

[a] Based on 1987 data.
[b] Furnace height from top of ash hopper to furnace nose.

6.1 L/LS-FGD RETROFIT DIFFICULTY FACTORS AND COSTS

6.1.1 Lime/Limestone FGD and Lime Spray Drying FGD Layouts

Figure 6-1 shows the general layout and location of the FGD control system. The retrofit ESPs are located between the chimneys and coal storage and handling area. To the east of unit 1 the area is congested with office buildings, coal conveyors, and other buildings. The only available space for absorber placement is to the west of unit 4. This area between unit 4 and the existing plant road is not in use and the area on the other side of the road is used for ash disposal. The lime and limestone storage/preparation and waste handling areas are located to the west of the absorbers. Table 6-2 presents the L/LS-FGD and LSD-FGD cases considered and the anticipated SO_2 removal.

6.1.2 Retrofit Difficulty and Scope Adder Costs

In this section, detailed retrofit FGD cost estimating procedures are used to develop retrofit factors for the Meramec plant. The site to the west of unit 4 is an open area with no major obstacle/obstruction. Placement of the FGD absorbers, sorbent handling, and waste disposal west of unit 4 will result in relocation of the plant road and ash pond. To address the need to replace these facilities a general facilities percentage of 8 percent was assigned. A low site access/congestion factor is assigned to the absorber sorbent and waste handling area for all units. Due to space constraints around the existing chimney from ESP placements and the coal handling area, a high site access/congestion and underground obstruction factor is assigned to unit 1-3 for the flue gas handling systems. Because it is easier to access the unit 4 chimney, a medium site access/congestion factor is assigned to the unit 4 flue gas handling system. Since unit 1 through 3 absorbers are placed a long distance from the existing chimneys, the cost of a new chimney for units 1-3 is included for the L/LS-FGD case. Building a new chimney is cost effective, since construction of outlet ductwork with high congestion factors would be eliminated and interference would also be reduced with other

Table 6-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR MERAMEC PLANT

Case Description	SO_2 Removal (percent)	Coal Sulfur (wt. percent)	Capacity Factor (percent)	SO_2 Reduction (tons per year)
L/LS-FGD				
Boiler 1	90	1.3	10.1	1,137
Boiler 2	90	1.3	12.8	1,478
Boiler 3	90	1.3	11.3	2,629
Boiler 4	90	1.3	11.6	3,473
LSD-FGD				
Boiler 1	76	1.3	10.1	964
Boiler 2	76	1.3	12.8	1,253
Boiler 3	76	1.3	11.3	2,228
Boiler 4	76	1.3	11.6	2,944

equipment. For flue gas handling, duct lengths range from 400 feet for unit 3 to 650 feet for unit 1. For unit 4, it was assumed that the existing chimney would be lined and reused. This results in 440 feet of flue gas duct work.

LSD with reused ESP was evaluated since all units presently have large SCAs (>490). For the LSD-FGD case, absorbers are located west of unit 4 in the same manner as L/LS-FGD. A low site access/congestion factor is also assigned to the absorber locations. For units 1 through 3, it is extremely difficult to tie-in the upstream of the ESPs at the outlet to the airheater due to the close proximity of the ESPs to each other, the chimneys, and the boiler house. Reuse of the existing unit 1-3 ESPs would require duct runs to be made over existing ESPs and ducting. As a result, high site access/congestion and underground obstructions are assigned to the unit 1-3 flue gas handling area. For unit 4, a medium site access/congestion factor is assigned to the flue gas handling system. Although it is relatively easy to access the outer duct run upstream of the unit 4 ESPs, it is difficult to access the inner duct run. As a result, a median of the access/congestion difficulty is used. Duct lengths range from 500 feet for unit 4 to 1,300 feet for unit 1. No costs are included for a possible extended outage to tie-in the existing ductwork between the airheater and ESPs. However, costs do include additional fan capacity needed to overcome the pressure drop due to the additional ductwork and absorbers.

Major scope adjustments are presented in Table 6-3. The major scope adjustment costs are for the conversion of the unit 1-4 fly ash handling system from wet to dry. This conversion is necessary to stabilize the L/LS-FGD generated waste and to prevent plugging of the sluice line for LSD-FGD.

The retrofit factors determined for L/LS-FGD cases range from 1.38 for unit 4 to 1.59 for unit 1. The retrofit factors for LSD-FGD cases range from 1.36 for unit 4 to 1.72 for unit 1. Tables 6-4 and 6-5 summarize the retrofit factor data for the L/LS-FGD and LSD-FGD technologies.

6.1.3 Simplified Versus Detailed Retrofit Factor Procedure Results

The previous section presents the results of the detailed procedures analysis based on a site visit made to Meramec plant. In this section, the

TABLE 6-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR MERAMEC PLANT

Scope Adjustment	Description[a]
• New chimney	For L/LS-FGD cases for boilers 1 through 3 ($10.51 - $14.05/kW).
• Chimney liner	Chimney liner for L/LS-FGD case for boiler 4 ($5.28/kW).
• Modify draft controls	Boiler draft control modifications/upgrades were required due to increased pressure drop and added fan capacity ($1.74 - $2.25/kW).
• Demolition and relocation	Relocation of a plant road and fly ash sluice lines for placement of the FGD units.
• Wet to dry ash handling system	To stabilize L/LS-FGD waste and to prevent plugging of the sluice line in LSD-FGD for all units ($8.21 - $9.07/kW).

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[a] Costs shown are based on 1987 dollars and have been adjusted for location, process, retrofit, and other considerations.

TABLE 6-4. SUMMARY OF RETROFIT FACTOR DATA FOR L/LS-FGD AT MERAMEC PLANT USING DETAILED PROCEDURES

Item	Boilers 1	2	3	4
Site Access/Congestion				
Reagent feed	Low	Low	Low	Low
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	Medium
Waste handling	Base	Base	Base	Base
General support equipment	Low	Low	Low	Low
ESP Upgrade	NA	NA	NA	NA
Underground Obstruction				
Reagent feed	Low	Low	Low	Low
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	High
Waste handling	Base	Base	Base	Base
General support equipment	Low	Low	Low	Low
ESP Upgrade	NA	NA	NA	NA
Total Inlet and Outlet Ductwork (ft.)	650	520	400	440
Scope Adders				
New chimney	Yes	Yes	Yes	No
Chimney liner	No	No	No	Yes
Draft controls	Yes	Yes	Yes	Yes
Wet to dry ash handling system	Yes	Yes	Yes	Yes
Retrofit Factors				
FGD System	1.59	1.53	1.48	1.38
ESP Upgrade	NA	NA	NA	NA
General Facilities (percent)	8	8	8	8
Engineering and Home Office Fees (percent)	11	11	11	11

NA = Not applicable.

TABLE 6-5. SUMMARY OF RETROFIT FACTOR DATA FOR LSD-FGD AT MERAMEC PLANT USING DETAILED PROCEDURES

Item	Boilers			
	1	2	3	4
Site Access/Congestion				
Reagent feed	Low	Low	Low	Low
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	Medium
Waste handling	NA	NA	NA	NA
General support equipment	Low	Low	Low	Low
ESP Upgrade	High	High	High	Medium
Underground Obstruction				
Reagent feed	Low	Low	Low	Low
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	Medium
Waste handling	NA	NA	NA	NA
General support equipment	Low	Low	Low	Low
ESP Upgrade	High	High	High	High
Total Inlet and Outlet Ductwork (ft.)	1,300	1,060	800	500
Scope Adders				
New chimney	No	No	No	No
Chimney liner	No	No	No	No
Draft controls	Yes	Yes	Yes	Yes
Wet to dry ash handling system	Yes	Yes	Yes	Yes
Retrofit Factors				
FGD System	1.72	1.63	1.52	1.36
ESP Upgrade	1.59	1.59	1.59	1.38
General Facilities (percent)	8	8	8	8
Engineering and Home Office Fees (percent)	11	11	11	11

NA = Not applicable.

simplified procedure results made before the site visit and revised after the site visit are compared with those obtained through using the detailed procedures.

Prior to the site visit, retrofit factors were developed based on a plot plan which did not show the retrofit ESP boxes and EIA-767 form. After the site visit, input variables to the simplified procedures were examined (i.e., site access/congestion, scope adders) for accuracy. All units have large retrofit ESP sizes and upgrading of the ESP with additional plate area would not likely be required.

Before the site visit, the absorbers were located in the space between the chimneys and coal storage and handling area because the retrofit ESPs were not shown on the plot plan provided. After the site visit, it became apparent that there is insufficient space available behind the units and the best location for the absorbers is the open area to the west of unit 4. Because of the different absorber location, site access/congestion and underground obstruction factors for FGD equipment have been adjusted accordingly. Duct lengths were also increased because of the location of the absorbers to the west of unit 4, rather than behind the chimney as was used prior to the site visit. Costs for the conversion of the the fly ash handling system from wet to dry are also added. These corrections have resulted in retrofit factor adjustments when using the simplified procedures, ranging from 6 to 14 percent for L/LS-FGD and 4 to 16 percent for LSD-FGD.

The capacity factors used for estimating operating costs were 16, 48, 65, and 40 percent for units 1-4, respectively, prior to the site visit. These factors were based on 1985 data. The reason for such a relatively high capacity factor was that the Sioux Plant had operational problems in 1985 which resulted in an increase in Meramec electrical output. After the site visits, these capacity factors were corrected based on 1987 data which are more representative of the Meramec operating practice.

Tables 6-6 through 6-7 present the retrofit factors developed using the simplified procedure methodology after the site visit. Table 6-8 presents the retrofit factors developed using the simplified procedure methodology prior to and after the site visit along with the detailed procedure results. The absolute percent differences between the simplified and detailed procedures after the site visit ranged from 0 to 3 percent for L/LS-FGD and 1 to

TABLE 6-6. SUMMARY OF RETROFIT FACTOR DATA FOR L/LS-FGD AT MERAMEC PLANT USING THE SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

Item	Boilers			
	1	2	3	4
Site Access/Congestion				
SO_2 removal	Low	Low	Low	Low
Flue gas handling	High	High	High	Medium
Ductwork distance (feet)	600-1,000	300-600	300-600	300-600
Scope Adjustments				
Wet to dry	Yes	Yes	Yes	Yes
Estimated cost (1,000$)	1,225	1,225	2,377	2,887
New chimney	Yes	Yes	Yes	No
Estimated cost (1,000$)	1,898	1,898	2,975	0
Other	No	No	No	No
Retrofit Factors				
FGD System	1.55	1.48	1.48	1.42
ESP reuse case				
Baghouse case				
ESP Upgrade	NA	NA	NA	NA
New Baghouse	NA	NA	NA	NA
General Facilities (percent)	8	8	8	10

NA = Not applicable.

TABLE 6-7. SUMMARY OF RETROFIT FACTOR DATA FOR LSD-FGD AT MERAMEC PLANT USING THE SIMPLIFIED PROCEDURES (AFTER SITE VISIT)

Item	Boilers			
	1	2	3	4
Site Access/Congestion				
SO_2 removal	Low	Low	Low	Low
Flue gas handling				
ESP reuse case	High	High	High	Medium
Baghouse case	NA	NA	NA	NA
Ductwork distance (feet)				
ESP reuse	1,000+	1,000+	600-1,000	300-600
Baghouse	NA	NA	NA	NA
ESP Reuse	High	High	High	Medium
New baghouse	NA	NA	NA	NA
Scope Adjustments				
Wet to dry	Yes	Yes	Yes	Yes
Estimated cost (1,000$)	1,225	1,225	2,399	2,887
New chimney	No	No	No	No
Estimated cost (1,000$)	0	0	0	0
Other	No	No	No	No
Retrofit Factors				
FGD System				
ESP reuse case	1.71	1.71	1.50	1.38
Baghouse case	NA	NA	NA	NA
ESP Upgrade	1.59	1.59	1.59	1.38
New Baghouse	NA	NA	NA	NA
General Facilities (percent)	8	8	8	8

NA = Not applicable.

TABLE 6-8. RETROFIT FACTOR COMPARISONS BETWEEN THE SIMPLIFIED AND DETAILED PROCEDURES

FGD CASES	Simplified Procedure (Prior to site visit)	Simplified Procedure (After site visit)	Detailed Procedure	Percent Difference[a]	
				Before[b]	After[c]
L/LS-FGD					
Unit 1	1.34	1.55	1.59	16	3
Unit 2	1.34	1.48	1.53	12	3
Unit 3	1.34	1.48	1.48	9	0
Unit 4	1.34	1.42	1.38	4	-2
LSD-FGD					
Unit 1	1.44	1.71	1.72	17	1
Unit 2	1.44	1.71	1.63	12	-4
Unit 3	1.44	1.50	1.52	6	2
Unit 4	1.44	1.38	1.36	-5	-1

[a] [(Detailed Procedure - Simplified Procedure)/Detailed Procedure] * 100.

[b] Before site visit.

[c] After site visit.

4 percent for LSD-FGD. These differences in the detailed procedures and simplified procedures after the site visit are due to less inputs to the simplified procedures as compared to the detailed procedure. For example, in the simplified procedures the underground obstruction factor the SO_2 removal and flue gas handling areas is assumed to be moderate, whereas for the detailed procedures these factors range from base to high. In addition, duct length is input as a range for the simplified procedures, while a specific duct length is used for the detailed procedures. The large difference between the simplified procedures before the site visit and the detailed procedures is due to the difference in FGD system location.

6.1.4 Summary of FGD Retrofit Costs

Table 6-9 presents the revised retrofit factors and costs for L/LS-FGD and LSD-FGD cases using the IAPCS cost model. Application of L/LS-FGD results in a reduction of plant level SO_2 emissions by approximately 8,734 tons per year, assuming a 90 percent level of control. The cost per ton of SO_2 removed ranges from $7,666 to $12,628.

Application of LSD-FGD would reduce the plant level SO_2 emissions by 7,404 tons per year assuming a 76 percent level of control. The cost per ton of SO_2 removed ranges from $4,792 to $9,397. The difference in the unit cost is mainly contributed to the economies-of-scale. Figure 6-2 presents the L/LS-FGD costs versus SO_2 reduction. The LSD-FGD cost results do not include costs for extended unit downtime required for ESP reuse. However, because units 1-3 are rarely used, this would not be a factor for these units. Although, it is likely that significant costs ($200/kW) would be incurred to extend the life of these units if they were to be equipped with FGD systems.

6.2 COAL SWITCHING AND PHYSICAL COAL CLEANING

To estimate the cost of coal switching, the simplified procedures used one of the IAPCS base coals as the switch coal. For the Meramec plant this coal was a West Virginia/Eastern Kentucky low sulfur bituminous coal. The IAPCS model assumes that the switch coal costs 5 and 15 dollars per ton more

TABLE 6-9. RETROFIT FACTORS AND COSTS FOR L/LS-FGD AND LSD-FGD USING THE IAPCS MODEL
(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	FGD Retrofit Factor	Particulate Control Retrofit Factor	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
L/LS-FGD	1	10.1	1.59	--	50.4	406.0	17,865	14.4	168.6	90	1,137
+ Additive	2	12.8	1.53	--	50.4	392.0	13,496	14.2	127.4	90	1,478
	3	11.3	1.48	--	50.4	278.7	11,059	20.7	104.4	90	2,629
	4	11.6	1.38	--	50.4	240.9	8,829	22.1	83.3	90	3,473
LSD-FGD	1	10.1	1.72	1.59	53.3	177.1	10,234	91.1	81.9	76	964
+ Reuse ESP	2	12.8	1.63	1.59	53.3	169.2	7,679	88.2	61.5	76	1,253
	3	11.3	1.52	1.59	53.3	139.9	6,688	13.3	53.5	76	2,228
	4	11.6	1.36	1.38	53.3	125.5	5,492	14.0	44.0	76	2,944

than the current coal. Additionally, costs for ESP upgrading using SO_3 conditioning and changes in waste disposal costs due to increases/decreases in ash disposal are included. The following data compares the properties of the coal currently fired at Meramec versus the IAPCS low sulfur bituminous coal.

Coal Parameter	Meramec	IAPCS
HHV - Btu per pound	11,505	12,058
Sulfur - percent	1.1	0.9
Ash - percent	8.6	16.6

The Meramec plant does not have adequate facilities to blend different coals. The plant currently receives coal by barge and coal for all units is stored and reclaimed from a single storage pile. The plant has the capability to receive coal by train; however, that portion of the coal handling system would require restoration. There would be no major additional capital costs for switching to a lower sulfur bituminous coal as long as blending was not desired. Use of a lower sulfur coal is not likely to require significant ESP upgrading. The Meramec plant has an emission limit of 0.12 lb per million BTU, and current emission levels are low (.001 - .006).

Physical coal cleaning was evaluated using the IAPCS coal database option. Using this option, IAPCS searches the database for a coal similar to the current coal using the following coal parameters: sulfur content, rank, and region. The level of coal cleaning is provided, and the model uses the cost of cleaning the database coal to the cleaning level specified. No information was provided by the plant during the visit to better determine the coal cleaning characteristics of the coals currently used. Because this Illinois coal is probably already being cleaned a great deal, only a 30 percent SO_2 removal through additional coal cleaning was estimated by IAPCS.

6.3. SELECTIVE CATALYTIC REDUCTION

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for SCR were reviewed for accuracy. The most important parameters which will impact the cost of retrofitting SCR are:

- reactor access and congestion,
- flue gas duct length to and from the reactor, and
- demolition costs of existing equipment and general facilities percentages.

These parameters are impacted by the location chosen for the SCR reactor. The SCR system type (tail-end) and the reactor location chosen before and after the site visit are the same. Table 6-10 presents the retrofit factors and scope adder costs estimated for the Meramec plant before and after the site visit. The SCR reactors for units 1 to 4 are located west of unit 4 in the same manner as the FGD absorbers. Reactors for units 1 through 4 are assigned low access/congestion factors because they are located in a relatively open area. The ammonia storage system is placed adjacent to the SCR reactors to the west of unit 4.

Prior to the site visit, SCR reactors were located between the chimneys and coal storage and handling area. As mentioned previously, retrofit ESPs are placed in this place. Therefore, SCR reactors were placed west of unit 4. As such, site access/congestion factor and underground obstruction factors were changed from medium and high to low. For scope adders, cost for a new chimney was added to unit 1-3 SCR reactors to reduce duct work interference with other equipment. Duct lengths were revised based on SCR reactor location. These changes were from 250 and 350 feet for units 1-2 and 3-4, respectively, to 650, 520, 400, and 440 feet with similar site access/congestion and underground obstruction factors as in conventional L/LS-FGD.

All NO_x control technologies are evaluated independently from SO_2 technologies. If further reductions in both SO_2 and NO_x emissions are necessary, the SCR reactors could be located downstream of the FGD absorbers. Some site access/congestion and underground obstructions exist for the reactors. However, short duct runs make this option cost effective.

Table 6-11 presents the revised estimated cost of retrofitting SCR at the Meramec boilers. Application of SCR would reduce NO_x emissions by 2,943 tons per year if 80 percent reduction can be achieved. The cost per ton of NO_x removed ranges from $20,411 to $42,061.

TABLE 6-10. SUMMARY OF SCR RETROFIT RESULTS FOR MERAMEC PLANT
(March 1988 Dollars)

	After Site Visit				Before Site Visit			
Boiler Number	1	2	3	4	1	2	3	4
Site Retrofit Results								
Site access and congestion								
for SCR reactor	Low	Low	Low	Low	High	High	High	High
for flue gas handling system	High	High	High	Medium				
Scope Adder Parameters								
Building demolition (1,000$)	1,898	1,898	2,975	0	0	0	0	0
Ductwork demolition (1,000$)	34	34	60	71	34	34	60	71
New duct length (feet)	650	520	400	440	250	250	350	350
New duct costs (1,000$)	5,317	4,253	5,052	5,468	1,496	1,496	3,327	3,663
New heat exchanger (1,000$)	2,261	2,261	3,523	4,013	2,261	2,261	3,523	4,013
Total Scope Adder Costs (1,000$)	9,510	8,446	11,610	9,552	3,791	3,791	6,823	7,747
Retrofit Factor for SCR	1.16	1.16	1.16	1.16	1.52	1.52	1.34	1.34
General Facilities (percent)	13	13	13	13	13	13	13	13

TABLE 6-11. RETROFIT FACTORS AND COSTS FOR SCR USING THE IAPCS MODEL

(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor	Scope Cost ($1,000)	General Factor (%)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent NO_x Removed	Tons/year NO_x Reduced
SCR 3 yr catalyst life	1	10.1	1.16	3,791	88.0	211.9	28,696.2	8.6	71.2	80	299
	2	12.8	1.16	3,791	88.0	204.0	21,630.0	8.4	53.7	80	389
	3	11.3	1.16	6,823	88.0	160.6	15,259.8	14.8	53.0	80	968
	4	11.6	1.16	7,747	88.0	139.9	12,810.4	16.4	44.5	80	1,279

6.4 SORBENT INJECTION AND REPOWERING

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most important parameters which will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance and difficulty of upgrade (access/congestion associated with adding plate area),
- need for converting wet ash handling system to a dry system, and
- sufficient flue gas residence time between the air heater and particulate control device to allow for DSD droplet drying (2 seconds of straight duct run) or humidification with FSI.

Based on the EIA-767 form, it was known prior to the site visit that the ESPs had an SCA of 492 to 545 and had good removal efficiencies relative to the emission limit of .12 lb/MMBTU. Additionally, it was assumed that the fly ash was disposed of dry and that sufficient duct residence time was available between the air heater and ESP to allow for adequate DSD droplet drying or, if not, that the ESP was large enough to apply the E-SO_x technology. The E-SO_x technology uses advanced particulate control concepts to enhance the performance of an existing ESP such that the first ESP section can be converted to a spray injection section. This technology is under field pilot scale development at this time.

Based on the site visit, it was learned that all units at Meramec originally had ESP boxes between the air heater and chimney and that additional boxes were later added to improve particulate control performance while burning lower sulfur coals. The additional boxes are located behind the chimney of each unit. For units 1 and 2, the flue gas ducting travels from the outlet of the old boxes around the chimney and over the new boxes. As such, there is plenty of droplet drying time for DSD and humidification time for FSI. For units 3 and 4, the flue gas ductwork leaves the outlet of the old boxes, goes around the chimney and directly into the new boxes. These duct runs are short and have a number of turns, thus making these units poor candidates for DSD and humidification injection. However, the old boxes would be good candidates for sorbent injection for the E-SO_x technology in conjunction with retrofit advance particulate control technology.

Sufficient duct residence time does appear to exist in front of the old boxes to allow for humidification when applying FSI. Although it had been assumed prior to the site visit that the access/congestion factor for particulate control upgrading is high, in fact, it is not likely that an increase in plate area would be needed with the sorbent injection technologies due to the positive effects of humidification on particulate control.

It was determined by the site visit that the plant uses a wet ash disposal system which would have to be converted to a dry system if any of the sorbent injection technologies were applied at Meramec. A misunderstanding in communications with company personnel resulted in assuming that the fly ash was already handled dry even though the EIA-767 form indicates wet ash disposal. Table 6-12 compares the before and after site visit estimates for the retrofit difficulty factors and scope adders for the Meramec units. The major difference in the estimates is due to the cost of converting the wet fly ash system to a dry handling system. This cost increases capital costs by 20 to 30 percent and annual operating costs by 5 to 10 percent. Table 6-13 presents the costs estimated to retrofit DSD and FSI at the Meramec plant.

Application of DSD at the Meramec units would reduce plant level SO_2 emissions by approximately 4,659 tons per year assuming a 90 percent level of control. The cost per ton of SO_2 ranges from $2,992 to $5,825.

Application of FSI at all units would reduce plant level SO_2 emissions by approximately 4,852 tons per year assuming a 50 percent level of control; the cost per ton of SO_2 ranges from $3,301 to $6,417.

TABLE 6-12. SUMMARY OF DSD/FSI RETROFIT RESULTS FOR MERAMEC PLANT
(March 1988 Dollars)

	After Site Visit				Before Site Visit		
Boiler Number	1	2	3	4	1-2	3	4
Site Access/Congestion							
Reagent preparation	Low	Low	Medium	Low	Medium	Medium	Medium
ESP Upgrade	High	High High	Medium	Medium	Medium	Medium	Medium
New baghouse	NA	NA	NA	NA	NA	NA	NA
Scope Adders							
Change ESP ash discharge system to dry handling	Yes	Yes	Yes	Yes	No	No	No
Estimated cost (1,000$)	1,225	1,225	2,399	2,887	NA	NA	NA
Additional duct work (ft.)							
New baghouse case	NA	NA	NA	NA	NA	NA	NA
Estimated cost (1,000$)	0	0	0	0	NA	NA	NA
ESP reuse case	0	0	0	0	NA	NA	NA
Estimate cost (1,000$)	0	0	0	0	NA	NA	NA
Duct demolition length (ft.)	50	50	50	50	50	50	50
Demolition cost (1,000$)	34	34	60	70	38	66	78
Total cost (1,000$)							
ESP upgrade case	1,259	1,259	2,459	2,957	38	66	78
New baghouse case	NA	NA	NA	NA	NA	NA	NA
Retrofit Factors							
Control system (DSD system only)	1.13	1.13	1.13	1.13	1.25	1.25	1.25
ESP upgrade	1.59	1.59	1.59	1.38	1.34	1.34	1.34
New baghouse	NA	NA	NA	NA	NA	NA	NA

NA = Not applicable.

TABLE 6-13. RETROFIT FACTORS AND COSTS FOR DSD/FSI USING THE IAPCS MODEL

(March 1988 Dollars)

Case Description	Boiler Number	Capacity Factor (%)	Retrofit Factor (ESP/FF)	Scope Cost ($1,000)	Capital Cost ($/kW)	Unit Cost ($/ton)	Annual Cost (million $)	Annualized Cost ($/MWhr)	Percent SO_2 Removed	Tons/year SO_2 Reduced
DSD + Reused ESP	1	10.1	1.59	1,259	59.1	7,974.1	4.9	40.7	49	615
	2	12.8	1.59	1,259	59.1	6,226.6	5.0	31.8	49	799
	3	11.3	1.59	2,459	46.1	4,628.3	6.6	23.6	49	1,421
	4	11.6	1.38	2,957	41.9	3,796.5	7.1	19.4	49	1,877
FSI + ESP	1	10.1	1.59	1,259	63.9	6,062.1	3.8	31.8	50	632
	2	12.8	1.59	1,259	63.9	4,806.3	3.9	25.2	50	821
	3	11.3	1.59	2,459	49.6	3,889.6	5.7	20.4	50	1,460
	4	11.6	1.38	2,957	44.8	3,260.6	6.3	17.1	50	1,929

SECTION 7

COST ESTIMATE COMPARISON OF FGD AT BECKJORD AND MIAMI FORT PLANTS

As part of the simplified procedure verification study, the Beckjord and Miami Fort steam plants of Cincinnati Gas and Electric (CG&E) were visited. In 1985, CG&E had Sargent and Lundy (S&L) develop budget (±15 percent) cost estimates for the retrofit of FGD at Beckjord units 5 and 6 and Miami Fort units 6 and 7. This report section presents the results of comparing the cost estimates for retrofitting lime FGD using the simplified procedures to the S&L cost estimates. Results of the evaluation of the other technologies are summarized in Section 2.0.

7.1 BECKJORD STEAM PLANT

The Beckjord steam plant is located within Clermont County, Ohio, as part of the CG&E system. The plant has six coal-fired boilers with a total gross generating capacity of 1201 MW. Figure 7-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7-1 presents operational data for the existing equipment at the Beckjord steam plant. Boilers 1-4 burn low sulfur coal (1.0 percent sulfur) while boilers 5-6 burn medium sulfur coal (2.1 percent sulfur). Coal shipments are received by barge and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for all boilers are controlled with retrofit ESPs. The ESPs for boilers 1-4 are located over the turbine houses; the ESPs for unit 5 are located on the boiler building roof and the ESPs for unit 6 are located on the boiler building roof and at ground level beside unit 6. Units 1-4 have a dry fly ash handling system and fly ash is disposed off-site or sluiced to ponds located north of the plant. Fly ash from units 5 and 6 is wet sluiced to ponds located south of the plant.

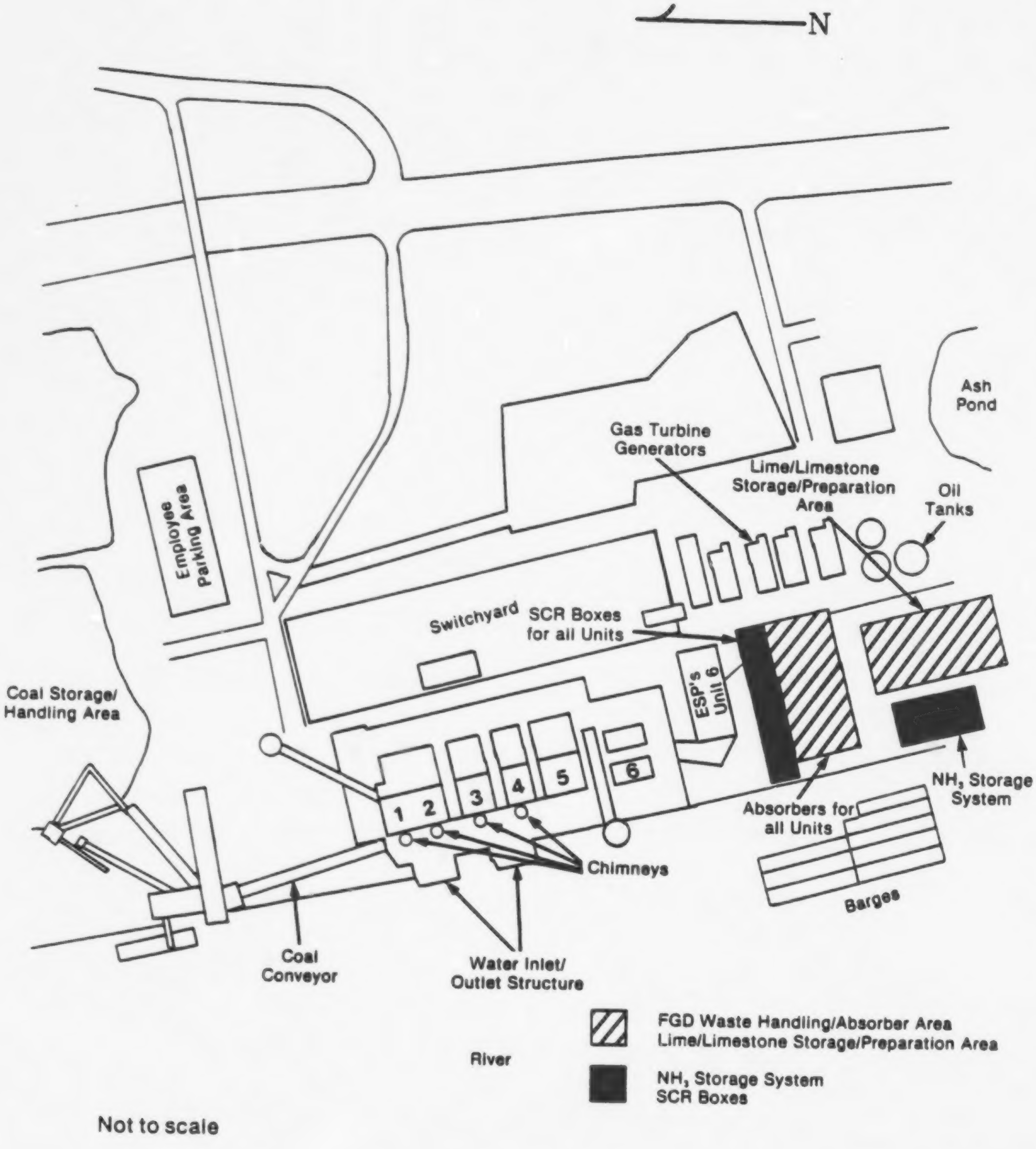
N
Ash Pond
Gas Turbine Generators
Lime/Limestone Storage/Preparation Area
Oil Tanks
Employee Parking Area
Switchyard
SCR Boxes for all Units
ESP's Unit 6
Coal Storage/ Handling Area
1
2
3
4
5
6
Absorbers for all Units
NH_3 Storage System
Chimneys
Barges
Coal Conveyor
Water Inlet/ Outlet Structure
▨ FGD Waste Handling/Absorber Area
Lime/Limestone Storage/Preparation Area
River
■ NH_3 Storage System
SCR Boxes
Not to scale

Figure 7-1. Beckjord Plant plot plan.

TABLE 7-1. BECKJORD STEAM PLANT OPERATIONAL DATA

Item	Units 1,2	Unit 3	Unit 4	Unit 5	Unit 6
Generating Capacity (MW-each)	100	135	162	255	449
Capacity Factor (percent)[a]	6,8	10	22	29	57
Installation Date	1952	1954	1958	1962	1969
Firing Type	TANG	FWF	TANG	TANG	TANG
Coal Sulfur Content (percent)	1.0	1.0	0.9	2.5	2.5
Coal Heating Value (Btu/Lb)	11000	11000	11000	11000	11000
Coal Ash Content (percent)	14.4	14.2	14.2	16.4	16.0
Fly Ash System	Dry Handling			Wet Sluice	
Ash Disposal Method	Off-site			On-site	
Stack Number	1,2	3	4	5	5
Coal Delivery Methods	Barge				
Particulate Control					
Type	ESP	ESP	ESP	ESP	ESP
Installation Date	1974	1973	1975	1976	1969/79
Emission (lb/MM Btu)	0.05	0.05	0.05	0.05	0.05
Removal Efficiency	99.5	99.5	99.5	99.5	99.5
Design Specification					
Sulfur Specification (percent)	1.0	1.0	1.0	1.0	2.5
Surface Area (1000 SQ FT)	82.6	123.1	119.9	216	203/832
Gas Exit Rate (1000 ACFM)	350	505	585	875	1600
SCA (SQ FT/1000 ACFM)	236	244	205	247	646
Outlet Temperature (^{o}F)	250	250	250	250	250

[a] Based on 1987 data.

7.1.1 Lime/Limestone FGD and Lime Spray Drying FGD Location

Figure 7-1 shows the general layout and location of the FGD control system assumed using the simplified procedures. Originally the absorbers for lime FGD units 1 and 2 were located north of unit 1 between the powerhouse and coal pile, close to the office building. The absorbers for unit 3-6 were located between the unit 6 ESPs and the ash pond. For units 1 and 2, a storage building required relocation; therefore, a factor of 7 percent was assigned to general facilities. Units 3-6 would require no major demolition/relocation; therefore, a base factor of 5 percent was assigned to general facilities. The lime storage/preparation area and waste handling area was located south of the plant between the powerhouse and the ash pond site, adjacent to the turbines.

During the site visit, plant personnel indicated that FGD absorbers for units 1-2 would not be located beside unit 1 but would likely be located south of unit 6. The plant personnel also indicated that FGD would not likely be considered as an SO_2 reduction option for units 1-4.

7.1.2 Retrofit Difficulty and Costs

For the absorber locations adjacent to unit 6, a medium site access/congestion factor was assigned due to the closeness to the river. For flue gas handling, various length duct runs would be required for each unit. For the absorber location adjacent to unit 1, unit 1 would require a medium duct run and unit 2 a long duct run. For the absorber location adjacent to unit 6, the duct run requirements for units 1-4 would be extreme, unit 5 would be high, and unit 6 would be short. For the flue gas handling system, units 1 and 2 were assigned a high access/congestion factor due to obstructions created by the other units, the unit 2 ESPs, and access difficulty to the chimney. For units 3-4, a high access/congestion factor was assigned because of the location of the chimney and obstructions caused by units 5-6 ESPs/chimneys. Unit 5 had a high access factor due to congestion created by unit 5 ESPs and obstructions caused by the unit 6 ESPs to access unit 5. For unit 6, a low access/congestion factor was designated because the ESPs are located beside unit 6 and access to the existing duct work on both the upstream and downstream of the ESPs would be easy.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Table 7-2. The largest scope adder for the Beckjord plant would be the conversion of units 5 and 6 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD cases. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. However, this conversion would not be necessary for units 1-4 because the existing fly ash handling system is dry. An additional scope adder would be the construction of a new chimney for all units to decrease the extreme duct runs. The overall retrofit factors determined for the L/LS-FGD cases were moderate to high.

Because Beckjord units 1-4 already burn low sulfur coal and the capacity factors for the units are low, CG&E would not likely retrofit these units with FGD. As a result, cost estimates were not available for comparison to IAPCS cost model estimates. Section 7.3 presents the IAPCS cost estimates and compares these estimates to S&L estimates developed for CG&E.

7.2 MIAMI FORT STEAM PLANT

The Miami Fort steam plant is located within Hamilton County, Ohio, as part of CG&E system. The plant contains four coal-fired boilers with a total gross generating capacity of 1308 MW. Boiler 8 is located beside the Ohio River south of the plant, boiler 7 is located north of the plant away from the river, and boilers 5 and 6 are in-between. Figure 7-2 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 7-3 presents operational data for the existing equipment at the Miami Fort steam plant. Boilers 5, 6, and 7 burn medium sulfur coal (1.9 to 2.3 percent sulfur) while boiler 8 burns low sulfur 1971 new source performance standard (NSPS) compliance coal (0.7 percent sulfur). Coal shipments are received by barge and conveyed to a coal storage and handling area located east of the plant.

Particulate matter emissions for the boilers are controlled with ESPs (units 5 and 6 are roof-mounted and units 7 and 8 are located behind each

TABLE 7-2. SUMMARY OF RETROFIT FACTOR DATA FOR BECKJORD UNITS 1-4

	L/S FGD TECHNOLOGY
Item	Units 1,2,3, AND 4
Site Access/Congestion	
SO2 Removal	Medium
Flue Gas Handling	High
ESP Reuse Case	
Baghouse Case	
Duct Work Distance (Feet)	1000 +
ESP Reuse	
Baghouse	
ESP Reuse	NA
New Baghouse	NA
Scope Adjustments	
Wet to Dry	No
Estimated Cost (1000$)	NA
New Chimney	Yes
Estimated Cost (1000$)	1134
Other	No
Retrofit Factors	
FGD System	1.84
ESP Reuse Case	
Baghouse Case	
ESP Upgrade	NA
NEW Baghouse	NA
General Facilities (percent)	5

TABLE 7-2. SUMMARY OF RETROFIT FACTOR DATA FOR BECKJORD UNITS 5-6 (Continued)

	L/LS FGD TECHNOLOGY	
Item	Unit 5	Unit 6
Site Access/Congestion		
SO2 Removal	Medium	Medium
Flue Gas Handling	High	Low
ESP Reuse Case		
Baghouse Case		
Duct Work Distance (Feet)	600-1000	0-100
ESP Reuse		
Baghouse		
ESP Reuse	NA	NA
New Baghouse	NA	NA
Scope Adjustments		
Wet To Dry	No	No
Estimated Cost (1000$)	NA	NA
New Chimney	Yes	No
Estimated Cost (1000$)	1785	0
Other	No	No
RETROFIT FACTORS		
FGD System	1.61	1.31
ESP Reuse Case		
Baghouse Case		
ESP Upgrade	NA	NA
New Baghouse	NA	NA
General Facilities (percent)	5	5

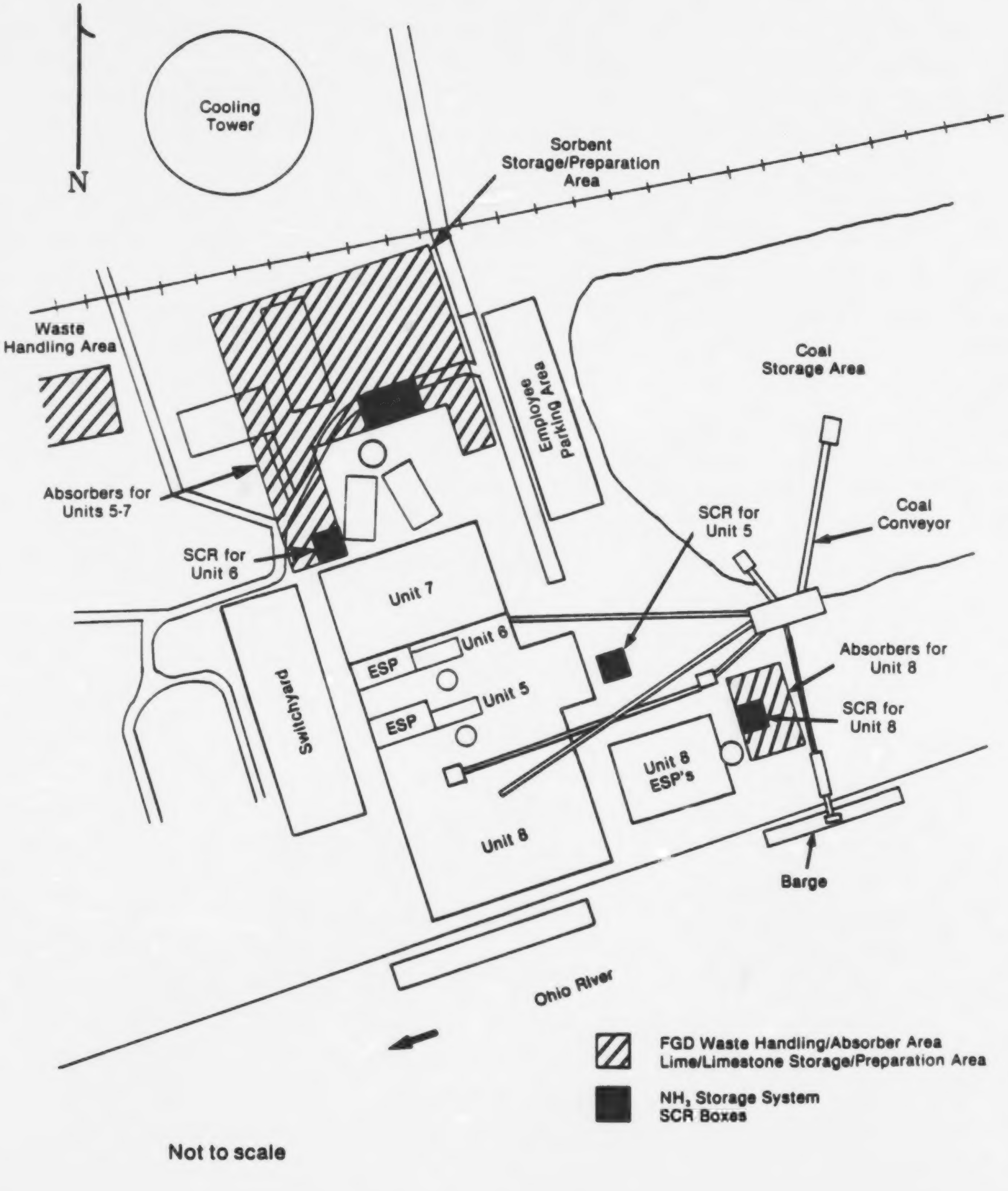
N
Cooling Tower
Sorbent Storage/Preparation Area
Waste Handling Area
Coal Storage Area
Employee Parking Area
Absorbers for Units 5-7
SCR for Unit 6
SCR for Unit 5
Coal Conveyor
Unit 7
Unit 6
ESP
Unit 5
ESP
Switchyard
Absorbers for Unit 8
SCR for Unit 8
Unit 8 ESP's
Unit 8
Barge
Ohio River
▨ FGD Waste Handling/Absorber Area Lime/Limestone Storage/Preparation Area
■ NH$_3$ Storage System SCR Boxes
Not to scale

Figure 7-2. Miami Fort Plant plot plan.

TABLE 7-3. MIAMI FORT STEAM PLANT OPERATIONAL DATA

Item	Unit 5	Unit 6	Unit 7	Unit 8
Generating Capacity (MW)	85	175	524	524
Capacity Factor (percent)*	40	71	67	56
Installation Date	1949	1960	1975	1978
Firing Type	FWF	TANG	OWF	OWF
Coal Sulfur Content (percent)	1.9	2.1	2.3	0.7
Coal Heating Value (Btu/lb)	11000	11000	11000	12300
Coal Ash Content (percent)	15.2	14.8	15.1	11.0
Fly Ash System	Wet	Wet	Dry	Dry
Ash Disposal Method	On-site		Off-site	
Stack Number	1	2	3	4
Coal Delivery Methods	Barge			
Particulate Control				
Type	ESP	ESP	ESP	ESP
Installation Date	1977	1976	1975	1978
Emission (lb/MM Btu)	0.05	0.05	0.05	0.05
Removal Efficiency	99.7	99.4	99.4	99.7
Design Specification				
Sulfur Specification (percent)	1.0	1.0	3.0	0.7
Surface Area (1000 sq ft)	185.3	119.9	557.3	663.5
Gas Exit Rate (1000 ACFM)	524	585	2020	2020
SCA (sq ft/1000 ACFM)	354	205	275	328
Outlet Temperature (°F)	310	310	310	310

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* Based on 1987 data.

respective boiler). Fly ash from units 5 and 6 is wet sluiced to ponds located west of the plant. Units 7 and 8 have a dry fly ash handling system and the fly ash is disposed off-site (2 miles).

7.2.1 Lime/Limestone FGD and Lime Spray Drying FGD Location

Figure 7-2 shows the general layout and location of the FGD control system. Before the site visit, the absorbers for unit 5 were located in a small space available between the coal conveyor and powerhouse building. Unit 6 absorbers were located adjacent to the unit 7 ESPs in an open area beside the switchyard (east) and powerhouse building (northwest). During the site visit, plant personnel said that FGD would not be applied to unit 5 because of the poor heat rate characteristics of this unit. The S&L study placed the unit 6 absorbers in the location described for the unit 5 absorbers.

For unit 7, the absorbers would be located behind the ESPs and chimney. Unit 8 was not considered in this study because it is a 1971 NSPS boiler burning low sulfur coal. For unit 5 or 6, a major part of the parking area and part of a major paved road would need to be demolished/relocated; therefore, a factor of 10 percent was assigned to general facilities. The unit 6 or 7 location near the unit 7 ESP/chimney would require the demolition/relocation of a warehouse building and one paved road; therefore, a factor of 7 percent was assigned to general facilities. For all units, the lime storage/preparation area would be located close to unit 7 in a relatively open area between the chimney/storage building, parallel to a major highway, and close to the cooling towers (other side of the highway). The waste handling area would be located adjacent to the storage/preparation handling area parallel to the highway.

7.2.2 Retrofit Difficulty and Costs

For the absorber location adjacent to unit 5 a high site access/congestion factor was assigned because of congestion created by the coal pile (west), powerhouse (east), and coal conveyors (south and north). For the absorber location near the unit 7 ESP/chimney a low site access/congestion factor was assigned due to the relatively open space available with no major obstacles/obstructions and very good accessibility.

For flue gas handling, short to moderate duct runs would be required for all units. Separate site access/congestion factors were assigned to each unit for the flue gas handling system as follows. For the absorber location adjacent to unit 5 a high access/congestion factor was assigned due to the access difficulty created by the powerhouse to route the flue gas from the ESPs to the absorbers and back to the roof-mounted chimney. For the absorber location adjacent to unit 7, unit 6 flue gas handling was assigned a medium access/congestion factor which reflects the access difficulty associated with routing flue gas from the ESPs to the absorbers. A low site access/congestion factor for flue gas handling was assigned to unit 7 due to the absorbers being located close to the chimney with no major obstacles/obstructions surrounding the chimney.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Table 7-4. The largest scope adder for the Miami Fort plant would be the conversion of the unit 6 fly ash conveying/disposal system from wet to dry. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. However, this conversion would not be necessary for unit 7 because the existing fly ash handling system is dry. The overall retrofit factors determined for the lime FGD cases ranged from low to high (1.24-1.66). Section 7.3 presents the IAPCS cost estimates for units 6 and 7 and compares these cost results to the S&L study.

7.3 COMPARISON OF IAPCS COST ESTIMATES TO UTILITY COST ESTIMATES

The FGD system cost estimates were developed by S&L for Beckjord units 5 and 6 and Miami Fort units 6 and 7. Tables 7-5 and 7-6 summarize the data available for these FGD system cost estimates. The S&L cost estimates include facilities for waste stabilization, an onsite emergency sludge pond, and offsite disposal of stabilized sludge. The cost of spare parts, sales tax, and transportation and disposal costs of stabilized sludge were not included in the estimate. Costs for escalation to 1992 and allowance for funds during construction developed by S&L were not considered.

TABLE 7-4. SUMMARY OF RETROFIT FACTOR DATA FOR MIAMI FORT UNITS 6 AND 7

	FGD TECHNOLOGY	
Item	UNIT 6 L/LS FGD	UNIT 7 L/LS FGD
SITE ACCESS/CONGESTION		
SO$_2$ REMOVAL	Low	Low
FLUE GAS HANDLING	MEDIUM	LOW
ESP REUSE CASE		
BAGHOUSE CASE		
DUCT WORK DISTANCE (FEET)	300-600	100-300
ESP REUSE		
BAGHOUSE		
ESP REUSE	NA	NA
NEW BAGHOUSE	NA	NA
SCOPE ADJUSTMENTS		
WET TO DRY	YES	NO
ESTIMATED COST (1000$)	1548	NA
NEW CHIMNEY	YES	NO
ESTIMATED COST (1000$)	1225	0
OTHER	NO	NO
RETROFIT FACTORS		
FGD SYSTEM	1.44	1.24
ESP REUSE CASE		
BAGHOUSE CASE		
ESP UPGRADE	NA	NA
NEW BAGHOUSE	NA	NA
GENERAL FACILITIES (PERCENT)	10	10

TABLE 7-5. FGD COST COMPARISON FOR BECKJORD UNITS 5 AND 6[a]

Cost Item	Sargent & Lundy Study	IAPCS Cost Estimates	
		Lime FGD	Organic Acid FGD
Total Direct Cost	113,410	98,650	83,031
Indirect Cost	17,011	15,310	12,882
Contingency	14,793	30,319	25,525
Total Capital Cost			
$	145,214	144,279	121,437
$/kw	203	202	170

[a] Based on a combined FGD system of 715 MW for units 5 and 6, coal sulfur content of 5.5 percent, and mid-1985 dollars.

TABLE 7-6 FGD COST COMPARISON FOR MIAMI FORT UNITS 6 AND 7

Cost Item	Capital Costs for Unit 6 (1985 $)			Capital Costs for Unit 7 (1985 $)		
	Sargent & Lundy	IAPCS Estimates		Sargent & Lundy	IAPCS Estimates	
	Estimate	Lime	Organic Acid	Estimate	Lime	Organic Acid
Total Direct Costs (1,000 $)	43,249	33,785	29,372	95,358	58,542	49,666
Indirect Costs (1,000 $)	6,487	6,757	5,874	13,304	11,708	9,933
Contingency (1,000 $)	5,641	10,437	9,078	12,438	17,967	15,248
Total Capital Costs (1,000 $)	49,736	50,979	44,225	109,662	88,217	74,847
($/kw)	276	283	246	210	169	143

The S&L total direct costs include mechanical, structure and improvement, and electrical construction costs. Structures and improvements include ground improvements, reactant unloading and handling system, SO_2 removal system, new chimney, and waste stabilization system. Electrical costs include transformers, switchgear, duct runs, conduits, etc. The cost of construction labor included in the estimate is based on the following:

1. May 1985 labor rates and fringe benefits;
2. Man-hours and efficiency of work as has occurred in similar work areas; and
3. Man-hour costs as required to attract labor for the job.

All costs for equipment, material, and labor are based on May 1985 dollars.

Tables 7-5 and 7-6 also present the IAPCS cost model estimates developed for Beckjord and Miami Fort. These costs were generated by incorporating the retrofit factor and indirect percentages presented in Tables 7-2 and 7-4 into IAPCS. The IAPCS indirect costs include general facilities (5-10 percent), engineering percentage (10-11 percent), and project (30 percent), and process (1.4 percent) contingency. The high project contingency is due to the cost estimate detail. By comparison, the S&L cost estimate has much greater detail and much lower project contingency (15 percent).

Comparing the conventional lime FGD total capital results shows the IAPCS and S&L estimates to be similar for Beckjord units 5 and 6 and Miami Fort unit 6. However, the IAPCS cost estimate for Miami Fort unit 7 is 20 percent lower than the S&L estimate. This appears to be due primarily to two factors. The factor which has the greatest impact is spare absorber capacity. The IAPCS cost estimates assume four absorbers plus one spare versus the S&L study which assumed two absorbers plus one spare. The second factor is that the S&L study estimates include the cost of a new chimney versus the IAPCS cost estimate which assumes reuse of the existing chimney (chimney liner costs included).

Also included on Tables 7-5 and 7-6 are the IAPCS cost estimates for FGD systems with organic acid additives. Use of organic acid additives results in about a 15 percent capital reduction. The reduction in cost is due to lower liquid to gas ratios which results in smaller diameter absorbers and smaller recirculating pump capacity.